Smart TSO-DSO interaction schemes, market architectures and ICT Solutions for the integration of ancillary services from demand side management and distributed generation

Aggregation models

D2.1

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About SmartNet

The project SmartNet (http://smartnet-project.eu) aims at providing architectures for optimized interaction between TSOs and DSOs in managing the exchange of information for monitoring, acquiring and operating ancillary services (frequency control, frequency restoration, congestion management and voltage regulation) both at local and national level, taking into account the European context. Local needs for ancillary services in distribution systems should be able to co-exist with system needs for balancing and congestion management. Resources located in distribution systems, like demand side management and distributed generation, are supposed to participate to the provision of ancillary services both locally and for the entire power system in the context of competitive ancillary services markets.

Within SmartNet, answers are sought for to the following questions:

- Which ancillary services could be provided from distribution grid level to the whole power system?
- How should the coordination between TSOs and DSOs be organized to optimize the processes of procurement and activation of flexibility by system operators?
- How should the architectures of the real time markets (in particular the markets for frequency restoration and congestion management) be consequently revised?
- What information has to be exchanged between system operators and how should the communication (ICT) be organized to guarantee observability and control of distributed generation, flexible demand and storage systems?

The objective is to develop an ad hoc simulation platform able to model physical network, market and ICT in order to analyse three national cases (Italy, Denmark, Spain). Different TSO-DSO coordination schemes are compared with reference to three selected national cases (Italian, Danish, Spanish).

The simulation platform is then scaled up to a full replica lab, where the performance of real controller devices is tested.

In addition, three physical pilots are developed for the same national cases testing specific technological solutions regarding:

- monitoring of generators in distribution networks while enabling them to participate to frequency and voltage regulation,
- capability of flexible demand to provide ancillary services for the system (thermal inertia of indoor swimming pools, distributed storage of base stations for telecommunication).

Partners

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List of Abbreviations and Acronyms

Acronym	Meaning
AS	Ancillary Services
BRP	Balance Responsible Party
CHP	Combined Heat and Power
CPLEX	A mixed-integer linear programming solver offered by IBM
DAM	Day-Ahead Market
DER	Distributed Energy Resource[1]
DG	Distributed Generation
DR	Demand Response
DoD	Depth-of-Discharge
DSO	Distribution System Operator
EES	Electric Energy Storage
ETP	Equivalent Thermal Parameter
EV	Electric Vehicle
G2S	Grid-to-Storage
HV	High Voltage
HVAC	Heating, Ventilation and Air Conditioning
IP	Integer Programming
LP	Linear Programming
LV	Low Voltage
MDC	Market Discomfort Cost
MV	Medium Voltage
O&M	Operation and Maintenance
PHES	Pumped Hydroelectric Storage
PV	Photovoltaic
RES	Renewable Energy Source
SO	System Operator
SoC	State of Charge
S2G	Storage-to-Grid
TCL	Thermostatically Controlled Load
TSO	Transmission System Operator
VPP	Virtual Power Plant
WP	Work Package

[1] DERs comprise of DGs, DR and EESs connected to low or medium voltage network, with their auxiliaries, protection and connection equipment, if any. SmartNet DERs include both dispatchable and variable resources.

Executive Summary

The flexibility coming from Distributed Energy Resources (DERs), connected at the distribution level, provides an opportunity for its use for the provision of local services to the Distribution System Operator (DSO) as well as ancillary services (AS) to the Transmission System Operator (TSO). However, in order to leverage the flexibility coming from DERs, there is a need for the development of the coordination schemes between TSOs and DSOs, as well as the new market architectures that are able to accept bids and offers from DERs.

One of the main goals of the SmartNet project is to demonstrate the possibility to leverage the flexibility from DERs, for the provision of AS [1] to the TSO, and local services to the DSO. Since DERs are typically small in terms of the flexibility quantity they can individually provide, the aggregator's role is to gather the flexibility provided by many DERs, and forward it, in the form of complex price-quantity bids, to the AS market. The aggregator plays a key role, by reducing the amount of data passed onto the AS market, which could potentially congest the clearing algorithm, developed in [2]. It also makes it possible for small DERs to participate in AS markets and obtain additional revenue streams.

This deliverable is the final report of SmartNet Task 2.2 "Offering models for a cluster of DERs." It is based on the deliverable D2.3 "Aggregation models: preliminary report" [3] and it implements the updates based on the feedback from work package (WP) 4, in which the mathematical models are implemented. The main goals of this deliverable are the development of mathematical models for the aggregation of a pool of DERs, the design of offering/bidding strategies, from a volume and activation cost perspective, and the design of a disaggregation procedure. The aggregation models use the individual DERs models, developed in [4], in order to generate the provision of the flexibility of active power through complex bids developed in [2]. The aggregation models determine the quantity and the cost of the flexibility provided by a portfolio of DERs, based on their physical and dynamic behaviour, and the design of the offering/bidding strategy in order to translate the aggregated behaviour of the pool of DERs into complex market offers and bids. Finally, this deliverable explains the disaggregation procedure after the market algorithm has determined prices and power levels. The disaggregation enables the allocation of the accepted bids among the individual DERs.

Due to a specific nature of individual DERs, different aggregation approaches are used for bidding to the SmartNet market. These are the physical (bottom-up), traces and justified approximation (hybrid) approaches. The physical (bottom-up) approach is used when the aggregator is familiar with the physical characteristics of each individual device it aggregates, and the traces approach when the load profiles and the cost associated with them are known. The justified approximation (hybrid) approach represents the entire population of aggregated devices by a single or a limited number of virtual devices. The aggregation of individual bids in all these approaches is performed by horizontal summation of the individual bid curves, which makes a disaggregation process straightforward, since it can be easily

identified which devices are going to be activated after the market clearing.

The SmartNet project's WP2 focuses on the design of market architectures that can foster and leverage the provision of ancillary services from DERs. Five aggregation models have been developed in the SmartNet project. Each model is characterized by a specific aggregation approach and type of the bid submitted to the AS market. These are summarized in Table 1.1.

Table 1.1 Overview of the aggregation models

Models	Aggregation approach	Type of bid
Atomic Loads	• Traces	• Non-curtailable UNIT bid
Combined Heat and Power (CHP) Units	• Physical	• STEP curtailable Q-bid
Thermostatically Controlled Loads (TCLs)	• Physical • Justified	• STEP non-curtailable Q-bid • STEP non-curtailable Qt-bid
Electric Energy Storage (EES) Units	• Physical	• STEP curtailable Q-bid • STEP curtailable Qt-bid
Curtailable Generation and Curtailable Loads	• Physical	• STEP curtailable Q-bid

Atomic Loads model describes the aggregation model for flexibility offered by loads, which have a fixed load profile, and can only provide flexibility by shifting their starting time or by replacing the scheduled load profile with an alternative fixed load profile. Once started, atomic loads cannot be paused or interrupted. These loads include wet appliances and industrial processes, i.e. shiftable loads explained in the deliverable D1.2 [4]. The flexibility of atomic loads is aggregated by using the traces approach. The aggregated bid is formed by solving a very simple optimization problem using integer programming (IP). A non-curtailable UNIT bid[2] is submitted to the market and the cost of activating a flexibility bid is defined by the atomic load aggregator as the cost of activating the alternative load profile minus the cost of activation of the scheduled profile.

CHP Units model aggregates CHP units by utilization of the physical (bottom-up) approach. The bidding is done one time step in advance. The model forms a STEP curtailable Q-bid[3] by taking into account possible constraints, such as the maximum ramp-up and ramp-down of each CHP plant and the power constraints.

TCLs model details the aggregation of TCLs, such as air conditioning systems, heat pumps, water heaters, electric heaters, etc. In order to aggregate single devices, this model uses physical (bottom-up)

[2] The non-curtailable UNIT bid [2] represents a pair of quantity and price that does not allow for the fractional acceptance of the bid. The bid is either fully accepted or rejected.
[3] The STEP curtailable Q-bid [2] defines an aggregated curve of flexibility with varying marginal cost for a single time step. It provides a vector of pairs of quantity Qs and price Ps along the Q-axis and has a single price for a range between two quantities. The market operator can accept any value between two quantities.

and justified approximation aggregation approach. It can offer STEP non-curtailable Q-bid[4] and STEP non-curtailable Qt-bid[5] to the market

EES Units model describes the aggregation for stationary and mobile battery storage and pumped hydroelectric storage (PHES). The introduction of EES units availability concept allows of merging stationary and mobile EES units into a general flexibility aggregation model. This general EES units aggregation model enable the aggregator to collect the flexibilities of different types of EES technologies (stationary, EV and PHES units) belonging to the same geographical area or a bidding node/zone. The aggregation applies physical bottom-up approach in order to form a "U-shaped" STEP curtailable Q-bid and STEP curtailable Qt-bid[6], since EES provides bidirectional flexibility.

Curtailable Generation and Curtailable Loads model includes the aggregation and bidding strategies for curtailable generation, such as wind, photovoltaics (PV) and small-scale hydropower, as well as curtailable loads, i.e. loads which can be curtailed without any rebound effects. They are combined into a unified flexibility model. The flexibility of a single unified device is aggregated using the physical (bottom-up) approach and offered to the SmartNet market as a STEP curtailable Q-bid. The STEP curtailable Q-bid is a "U-shaped" bid, given the bidirectional flexibility of a unified device.

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[4] The STEP non-curtailable Q-bid [2] is like its curtailable coequal, with the difference that the market operator can either fully accept or reject the total energy quantity Q at a price P, or higher.

[5] The STEP non-curtailable Qt-bid [2] defines aggregated curves of flexibility for a series of consecutive time steps. It essentially offers a non-curtailable Q-bid for a series of time steps within the window of optimization and allow expressing in advance the availability of flexibility for the future time steps.

[6] The STEP curtailable Qt-bid [2], offers STEP curtailable Q-bid for a series of time steps within the window of optimization.

1 Introduction

1.1 Scope of the document

This document serves as the output of Task 2.2 “Offering models for a cluster of DERs,” of the SmartNet project. This deliverable describes the mathematical aggregation models of DERs, namely demand response (DR), distributed generation (DG) and EESs, in order to express the amount and price of ancillary service they are willing to provide in the form of market bids. The outcomes of the deliverable D2.1 are implemented and integrated in the WP4 simulation environment.

Through the aggregation of small-scale DG, loads and EES units, it is possible to include their bids in the electricity market. These complex offers and bids take account of the physical and dynamic characteristics of the different DERs, provided by the deliverable D1.2 [4], whereby they are still simple enough so that they can be processed by the market clearing algorithms described in the deliverable D2.4 [2]. Individual DERs are classified into eight categories based on the modelling similarities [4]. These are: variable renewable energy sources (RES’s)/curtailable generation, stationary EES, electric vehicles (EVs), conventional generators, CHP, TCLs, shiftable loads and curtailable loads. Figure 1.1 shows the aggregators’ block input and output, i.e. the information flow between the aggregator, individual DERs and the market clearing algorithm.

Figure 1.1 Illustration of aggregation, bidding and disaggregation processes

An aggregator acts as an intermediary between the flexibility service providers, and the market, with a very clear role of aggregation[7] of the available flexibility volume. An aggregator is also in charge of the disaggregation, also referred to as allocation, or resources’ activation, after a successful aggregation and market clearing have taken place. In terms of the power system’s operation, disaggregation is equivalent to the generation economic dispatch, plus unit (de)commitment.

The DERs’ aggregation has previously been considered in [5] and [6]. The ADDRESS project [5] studies the aggregation of household appliances like washing machines, dishwashers, tumble driers, air conditioning systems, water heaters, etc. The aggregator uses the appliances’ flexibility to participate in the day-ahead and intraday energy markets. It is taken into account that the flexibility can be activated a few times per day because of the constraints associated with the devices (for example washing machines

[7] The term aggregation implies horizontal summation of the flexibility volume at rising cost.

are used usually once per day). The ADDRESS project uses a probability based parameterization of the devices. In this approach it is not needed to know the parameters of each device, but to have some probability distribution of the parameters. These distributions contain the information about the penetration percentage of the appliances (percentage of households having washing machine, air conditioning, etc.), devices' usage probabilities (percentage of washing machines that are started at 00:00, at 01:00, etc.), and other parameters in a similar way. When providing flexibility the distribution network constraints are taken account of [7], sometimes leading to a curtailed aggregator's response. The aggregator conducts an optimization with the objective to maximize the difference between the cost of the energy bought in the market and the price charged to the end consumer.

The FENIX project [6] uses the concept of the virtual power plant (VPP) in order to represent the aggregated profile and the output of the DER portfolio at the same geographical location. At the transmission level – distribution level interface VPP presents a single profile representing the whole local network, in a same way a TSO has the characterization of a transmission-connected generation. Therefore, in FENIX a VPP is considered a complex large-scale generator, as shown in Figure 1.2. The concept of VPP enables DERs' participation in a wide range of markets (e.g. forward, day-ahead, intraday and balancing/AS markets), while managing local network power flow and voltage constraints [8]. VPP offers different duration of responses, since it consists of different technologies, following different operating regimes. Hence, this concept enables a single aggregator to build bids by combining fast responding short lasting and slow responding long lasting flexibilities.

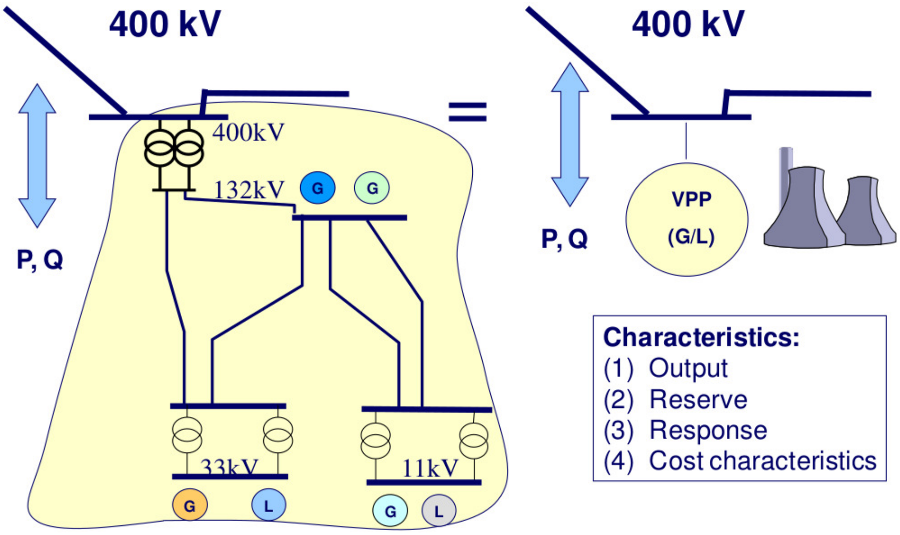

Figure 1.2 Characterization of DERs as a VPP in the FENIX project [6]

However, when considering SmartNet's near real-time AS market, a drawback of the FENIX approach is the complexity of the aggregation and disaggregation process. The complex disaggregation tends to add significant latency in response to the market clearing. Hence, unlike the aggregator in the FENIX project, SmartNet uses several technology specific aggregation models, aimed at separate DER categories, in order

to remain true to the physical constraints of the devices being aggregated, while enabling a fast and straightforward aggregation/disaggregation procedure. When it comes to the aggregation process, the more distinct the features of the aggregated devices are, the less accurate the approximations can become during their aggregation, and the more difficulties can arise during the disaggregation stage. Therefore, in the SmartNet project, DER devices that are reasonably similar in terms of their specific core features are grouped together. Hence, in the aggregation process, stationary EES and EVs are together considered as EES units, curtailable generation and curtailable loads are grouped into a unified model, wet appliances and industrial processes are grouped into atomic loads, TCLs are considered in TCLs model and CHP is considered in the CHP model. The grouping of DERs categories, done according to the individual models' constraints similarities, provided by [4], simplifies the bidding system and satisfies, at the same time, distribution network technical constraints. The five aggregation models, introduced in this document and aimed at separate DERs categories, are:

1. Atomic Loads,
2. CHP Units,
3. TCLs,
4. EES Units,
5. Curtailable Generation and Curtailable Loads.

As the market clearing mechanism is able to cope with multiple bids originating from the same aggregator, the simplest approach is for the aggregator to allow all five aggregation-type-specific categories, mentioned above, to generate bids for their own aggregated devices. That is to say, a single aggregator can use several aggregation models for providing its bids. By doing so, every bid that is accepted by the market can then be assigned to the corresponding device-type-specific disaggregation algorithm, which is best equipped for optimally distributing the allocated flexibility over its individual devices. The reason behind this approach is the fact that there is no need to build an overarching aggregation model, as it would inevitably make the disaggregation complex, i.e. it would be hard to identify the bids belonging to the individual devices. Although the aggregator in SmartNet can combine different duration of flexibilities, coming from different technologies, just like in FENIX, the drawback of this approach is the increased number of bids, since several simpler aggregation models are used instead of a single complex one.

1.2 Document structure

This deliverable is divided into a number of chapters in order to describe the aggregation and disaggregation process of a pool of DERs, as well as challenges associated with them.

In order to understand the cost of the provision of flexibility, i.e. the aggregator's flexibility cost, of each model, the overview of the general structure of the flexibility cost is discussed in Chapter 2. The aggregator's flexibility cost consists of the direct costs related to aggregated DER technology and the

indirect cost, associated with the aggregator, depends on a prediction of the price at which the aggregator would buy the additional consumption of electricity due to the rebound/payback effect.

Market arbitrage, as well as its incorporation in the flexibility cost framework, is described in the context of market discomfort cost, in Chapter 3.

Chapter 4 gives a summary of different aggregation approaches, used for bidding in the electricity market, alongside with their advantages and shortcomings.

Five aggregation models, mentioned above, are described in detail in Chapter 5. Each model determines the quantity and the cost of the active power flexibility provided by a portfolio of DERs based on their physical and dynamic behaviour. It also develops bidding strategy for submitting complex bids to the market.

Disaggregation for a pool of DERs is explained in Chapter 6. It is performed after the market algorithm has determined prices and power levels and it implies allocation of the accepted offers and bids among the individual DERs.

Chapter 7 gives an overview of the main conclusions, based on the results presented in this deliverable, as well as the updates done to the aggregation models since finalizing the preliminary report D2.3 [3].

There are also two appendices. Appendix A (Chapter 9) provides the highlights of the updates done since the preliminary report D2.3, and Appendix B (Chapter 10) provides the responses to the comments from the Advisory Board.

2 Flexibility Cost Framework

In order to define the aggregator's flexibility cost, of a pool of DERs to be submitted to the AS market, an aggregator needs the information about the cost of the provision of a certain amount of flexibility by a DER. This cost represents the changes in the cost compared to the base case when no flexibility has been provided for the aggregator, which represents the baseline power profile of the DER owner[8]. There are different ways of obtaining/estimating this baseline power profile, depending on the DER category, as well as other factors [4]. In this document, it is presumed that the baseline is obtained from the previous market, day-ahead or intraday, for all DER types. Note that the strategy for the intraday baseline calculation will be investigated in the SmartNet project.

The flexibility cost of a DER, at time step t, can be defined as the sum of the following components [4]:

$$c_{DER,t}^{\text{flex}} = c_{DER,t}^{\text{discomfort}} + c_{DER,t}^{\text{indirect}} + c_{DER,t}^{\text{operational}} + \Delta_{DER,t}^{\text{revenue}}, \forall DER, \forall t, \quad (1)$$

where:

- Discomfort cost, $c_{DER,t}^{\text{discomfort}}$, quantifies how the usage of a DER for flexibility is affecting its user/owner.
- Indirect cost, $c_{DER,t}^{\text{indirect}}$, occurs in cases when there are rebound/payback effects, which are not part of the provided flexibility. It represents changes of costs/revenues indirectly implied by the provision of the flexibility, for periods after the activation of the flexibility. It could also come from the aggregator's choice to bid in those time-steps, in the rebound direction.
- Operational costs, $c_{DER,t}^{\text{operational}}$, represents the change of direct costs associated with the change in the operation of the DER during the activation of the flexibility. This can include fuel cost, gases emission cost, maintenance cost, aging cost, start-up and shut-down costs, other variable costs (e.g. in process industry: EES costs, raw material costs, etc.), or electricity consumption costs. Note that aging cost represents the cost related to additional aging of the DER as a result of being activated for the flexibility.
- Revenue change, $\Delta_{DER,t}^{\text{revenue}}$, represents the change of revenues for a DER, during the activation of the flexibility. This can include revenues from subsidies, product sales (in process industry) or electricity production sales.

Since the SmartNet project considers DERs that are providing bidirectional flexibility, the absolute supply and demand are not important, but the relative change in reference to the baseline. Two situations can be distinguished:

[8] DER owner is also referred to as DER agent in the deliverable D1.2.

- Downward flexibility, which represents a decrease in the generation output/EES discharge, or an increase in consumption/EES charging. Its amount is always less than or equal to zero.
- Upward flexibility, which represents an increase in the generation output/EES discharge or a decrease in consumption/EES charging. Its amount is greater than or equal to zero.

For the DERs considered, there is a difference between the downward flexibility activation $c_{\mathrm{DER},t}^{\mathrm{flex},-}$, and the upward flexibility activation $c_{\mathrm{DER},t}^{\mathrm{flex},+}$, from the bidding cost perspective. This is further elaborated in the corresponding sections of Chapter 5.

Moreover, from the bidding cost perspective, there is a difference between:

- the positive cost flexibility and
- the negative cost flexibility.

In the case when the flexibility cost is positive, it represents the minimum amount of money a bidder is requesting to receive for providing the flexibility. In the case when the flexibility cost is negative, then it represents the maximum amount of money a bidder is willing to pay to the market, for providing the flexibility [2].

In order to define its overall flexibility cost, the aggregator needs information regarding the costs mentioned above. However, while the indirect cost of a DER device depends on the tariff structure to which the DER owner is exposed (firm or non-firm energy tariffs) [4], the overall aggregator's flexibility cost, linked to the particular DER technology, does not depend on these tariffs. The aggregator's indirect cost depends on a prediction of the price at which the aggregator would buy the additional consumption of electricity due to the rebound/payback effect.

The aggregator's flexibility cost varies, depending on the type of DER technology being aggregated. The flexibility cost is further explained and discussed separately for each aggregation model that is developed in Chapter 5 of this document. Note, that each model is using its own cost notations.

While the direct cost is directly related to DER technology (fuel, discomfort, etc.), indirect cost depends on aggregator's bidding, as well as the market design. Hence, it is associated with the aggregator, rather than the DER. The indirect cost is discussed, in detail, in the section below, and the direct flexibility costs are detailed, for each DER type, in the deliverable D1.2 [4] and the corresponding sections of Chapter 5.

2.1 Indirect Cost

Before discussing the indirect cost, it should be noted that the SmartNet project considers a complex market with receding time horizon as well as the simpler markets (closer to actual situation in Denmark, Spain and Italy), for which there will only be one time step (of 15min, 30min, 1hour duration). Therefore, the following is assumed:

- Day-ahead (as well as intraday) markets have already been cleared.
- The result of these markets yields a baseline to be fulfilled by the Balance Responsible Party[9] (BRP). In the SmartNet project it is assumed that the aggregator, bidding in the AS market, is such BRP.
- If the TSO requests to modify the baseline of the BRP in order to solve problems in the system, the balance perimeter of the BRP will be modified such that the required activated flexibility is not penalized. The TSO will not charge the aggregator/BRP with the imbalance costs within the time horizon of the market, since imbalance costs are charged for problems created by actors in the system, not for solving them.

The indirect cost or revenue is caused by the rebound/payback effect due to the provision of flexibility. The rebound/payback effect is illustrated in Figure 2.1. It shows the baseline power (solid line), the upward flexibility activation (dotdash line) during a single time step t and the rebound/payback effects (dashed line) which happens at later time steps e.g. at time steps $t+1$, $t+2$ and $t+3$.

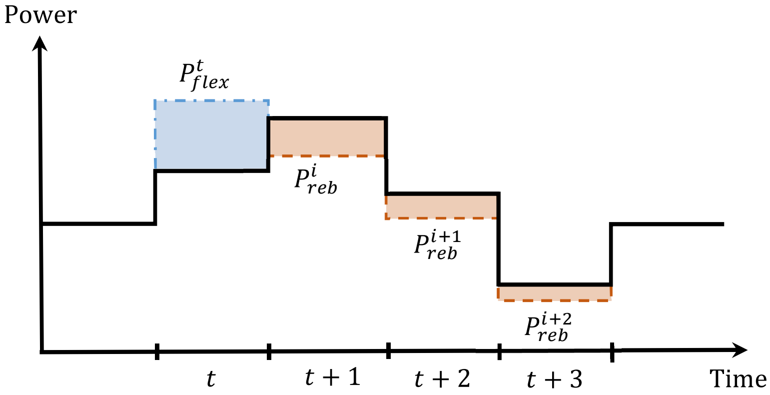

Figure 2.1 Example of an upward flexibility activation with three payback periods

If there is no rebound/payback effect, the indirect cost is equal to zero. However, if there is a rebound/payback effect associated with the provision of flexibility, several cases can be distinguished:

- If the flexible aggregated asset has a rebound/payback effect which occurs **after** the time horizon of the market, then there is a non-zero indirect cost for the aggregator/BRP. This implies that the baseline of the aggregator/BRP is modified after the time horizon of the market and since the effect is outside of the market time horizon, the BRP will be penalized through the classical imbalance mechanism. Thus, the indirect cost is not zero and should take this cost into account in the bidding.

  In this case, the indirect cost has to be estimated and taken into consideration for generating

[9] A BRP must be appointed for every grid access point, i.e. every point where energy injections or offtakes are performed. In case an imbalance between the injections and offtakes is recorded at an access point, an imbalance tariff is applied [9].

the bids. The following formula should be applied:

$$c_{DER,t}^{\text{indirect}} = \sum_{i=t_{end}^{bid}+1}^{t_{end}^{reb}} \lambda_{dev}^{i} P_{reb}^{i}\, \Delta t \tag{2}$$

where:

- t_{end}^{bid} is the end time step of the bid;
- t_{end}^{reb} is the end time step of the rebound period;
- λ_{dev}^{i} is the deviation price at time step *i*;
- P_{reb}^{i} is the rebound power at time step *i*;
- Δt is the time step duration.

The deviation price relates to the deviation from the scheduled baseline, and it is applied whenever there is an indirect cost. The estimation of λ_{dev}^{i} can be very complex because it is not known beforehand. This could make it necessary for the aggregator to develop a specific price forecasting tools to estimate them. The development of this tool is out of the scope of the Smartnet project. Instead, several assumptions could be made:

- The TSO publishes deviation prices in real time. While this is currently the case in The Netherlands [10] and Belgium [11], other countries in Europe (e.g. Denmark) are also considering the implementation of this approach. In this scenario, it is possible to use the most recent real-time deviation prices as the best approximation for future deviation prices and short time horizons.
- The aggregator has its own forecasting tools for deviation prices. In this case, deviation prices are generated using historical prices together with a random value representing the error.

- If the flexible aggregated asset has a rebound/payback effect **limited to** the time horizon of the market, there are two different subcases:

  a. The aggregator makes use of a complex bid (see Qt-bid in [2]) in which it defines an integral constraint such that at the end of the period, which the aggregator is bidding for, the device needs to be back on the (day-ahead) baseline, and is not concerned with the down/up deviations in the meantime –the asset's operation is left up to the TSO/DSO according to the flexibility needs by the system.

     In this case, the indirect cost is equal to zero.

$$c_{DER,t}^{\text{indirect}} = 0 \tag{3}$$

     However, the integral constraint has to consider the sum of the activated flexibility energy and the rebound energy. In a simplified approach, it could be considered that

its value is equal to zero[10]. This could be especially true for atomic loads and for TCLs, for short time periods, in which the external conditions, such as external temperature and internal uncontrolled thermal gains, do not change significantly. However, in the more strict case, the integral of the power should be calculated by the following formula:

$$E_{int} = E_{flex} + E_{reb} = \sum_{i=t_{ini}^{bid}}^{t_{end}^{bid}} P_{flex}^{i} \Delta t + \sum_{i=t_{end}^{bid}+1}^{t_{end}^{reb}} P_{reb}^{i} \Delta t \qquad (4)$$

where:

- E_{int} is the integral energy constraint;
- E_{flex} is the activated flexibility energy;
- E_{reb} is the rebound energy;
- t_{ini}^{bid} is the initial time step of the bid;
- t_{end}^{bid} is the end time step of the bid;
- t_{end}^{reb} is the end time step of the rebound period;
- P_{flex}^{i} is the power flexibility at time step *i*;
- P_{reb}^{i} is the rebound power at time step *i*;
- Δt is the time step duration.

b. The aggregator defines bids with intra-bid temporal constraints: Assumes that the flexibility market allows incorporating "Accept-All-Time-Steps-Or-None" constraint (see [2]). In this case, the indirect cost will be zero for the aggregator since the power profile offered includes both, the flexibility period and the rebound period.

c. The aggregator decides (option 1, aggregator choice) or is forced (option 2, the market does not offer the integral constraint) to use a simple bid (Q-bid in [2]), i.e. the aggregator focuses on providing flexibility for the next time step (e.g. 5-min) and not on the whole time horizon of the market. In this case, the analysis is the same as for case 1, described above.

   This case is not considered in the SmartNet project, as i) it would not be optimal for the aggregator to use simple bid while more complex ones, which are also easier to build, are available, and ii) it is not very likely that a market which has a receding time horizon, with multiple time steps, does not allow integral constraints for the bids.

[10] In reality integral of energy is usually non-zero, either due to internal device losses, temperature gains, etc. meaning the net energy exchange between the grid and the device is negative.

3 Market Discomfort Cost

In the ever-increasingly complex energy markets, and particularly in the Pan-European electricity markets, supply and demand are satisfied in series of subsequent market layers, which respond to different needs and constraints, starting from the long-term futures products, which serve for hedging price risk several years ahead, until the real-time dispatching of flexible units. In between we find a sequence of markets that can be summarized as follows:

- Day-ahead (or Spot): This takes place the day-ahead prior to delivery in the form of a supply and demand auction for every hour of delivery. Typically, the day-ahead market closes around noon. It is considered the most important market since all generation and consumption is obliged to participate, volume matching and price setting is performed under the mechanics of market flow-based coupling, and subject to complex constraints. Shortly after 12 noon, the price for each hour and balancing zone is set accordingly and day-ahead positions (nominations) are communicated to producers and consumers. This sets the day-ahead baseline for generation and consumption.
- Intraday: Since the day-ahead auction takes place several hours before delivery, market operators typically arrange intraday markets working as trading platforms (e.g. EPEX-Spot) [12]-[17]. Participation to these is not yet fully compulsory, serving to exchange bilaterally volumes for standard traded products such as hours, half hours or quarters of the hour. Other market operators have adopted the mechanics of intraday sequence of auctions (e.g. Spain and Italy). These markets serve as platforms to exchange deltas in forecast for production or consumption, thereby signaling the difference in supply and demand equilibrium from the forecasts at day-ahead auction (noon of D-1), until that particular trading moment. Intraday markets and auctions allow trading of electricity, being delivered in the future, until a given lead-time before delivery, so-called "gate closure," which normally represents the last moment to adjust one's position (the intraday baseline) towards the market and system operator (SO), before the real-time delivery.
- Ancillary markets: With the development of the electricity markets, TSO's have further developed the ancillary (balancing) markets, enhancing their transparency, openness and structure, bringing opportunities for additional revenues to flexible assets. The ancillary markets are activated in between the intraday gate closure and real-time delivery; they are steered by TSOs, who have the most updated information on the actual power transmission grid status and who operate the transmission grids in order to maximize the security and cost-efficiency of the electricity supply infrastructure. The ancillary markets are organized as capacity auctions where flexible consumers/producers bid their ability to re-dispatch volumes from their intraday-baseline in exchange for a profit; that is: a consumer will offer to curtail its consumption (thereby liberating volumes to the system or up-regulating) if the

price paid for such volume is significantly higher compared to the price previously paid for the volume. Inversely, a generator would offer to curtail its production (thereby removing volumes from the system, buy-back or down-regulate) in case it can buy-back the production at a price significantly cheaper than the one earlier received on the previous markets.

The SmartNet market is positioned in the last layer (ancillary), near real time, therefore comes after at least two very important market layers that have conditioned the positions of its participants (flexibility owners). With the ambitious targets for the integration of variable renewable generation into our Pan-European networks, the demand for distributed flexibility assets grows accordingly, empowering the role of demand response (DR) and dynamic asset management.

Typically, flexibility has two possible directions when scheduling its operation. A flexible asset can curtail consumption or turn its flexibility into its ability to consume more than what was initially planned. Therefore, a flexible asset reaches the SmartNet auction with flexibility in one of the directions, as a consequence of its previous choices. In other words, the choice of a DER to make itself available for up or down-regulation in one market is constrained by its choice in the "previous market." In the SmartNet market, the previous market is intraday baseline or a previous SmartNet market, and in intraday would be DAM baseline or a previous intraday market.

It is also worth mentioning that flexibility is not necessarily symmetric, as is the case for renewable generation curtailment. These rely on the resource availability and their bidding strategy tilts more towards down-regulating since, regardless of the magnitude of their forecast error, they can always curtail their output further and further. However, even if they would use the forecasted power increase for bidding in SmartNet, it is not under control, which would result in a preferential participation to down-regulation.

The sequence of markets established by the day-head, the intraday and the SmartNet market represent a sequence of opportunities to valorize DERs' flexibility, constrained by DERs' positions in the previous markets, as it is further explained below. This effect works in two ways, which are significant to our modeling exercise:

- On one hand, the SmartNet market comes last when deciding how to act in real time. This means that the aggregator's decision is constrained in the (up or down-regulation) direction relative to its previous actions.
- Secondly, in the case of complex flexibility from demand assets, it often happens that an "activation" in one period has an impact on the available flexibility in future periods. This is the case, for instance, in some battery storage configurations, cogenerations, TCLs, wet-appliances, etc. There could be a limited number of activations per day, or there could be integral constrains that render the choice to activate now into the impossibility to activate later, thereby giving up on the future value of the flexibility within a given time horizon. Since

the current value of the future energy delivery is available in a transparent intraday market, DERs and aggregators face a choice between activations, hence between the current real-time (SmartNet) prices and the current intraday prices or the future intraday/SmartNet prices.

In Figure 3.1 we present the case for a consumption asset whose marginal cost to curtail is above the day-ahead price for a given period, hence it has no curtailment programmed. At the present point of time, intraday price signal anticipated an “issue” in the network, which suggests bidding into SmartNet. However, in an efficient market, intraday prices should signal the issue, thereby we can expect market players to react and we shall see how intraday prices take into consideration the updated view on the situation.

The aggregator forms a vision of the expected clearing price for upward flexibility (load curtailment) in the future. Provided that the number of curtailment activations is limited, its marginal activation cost might increase for the future activation on the condition that it is activated now. Hence, the aggregator will consider a risk premium that takes into consideration the possible future market related variables, as well as its own forecast error.

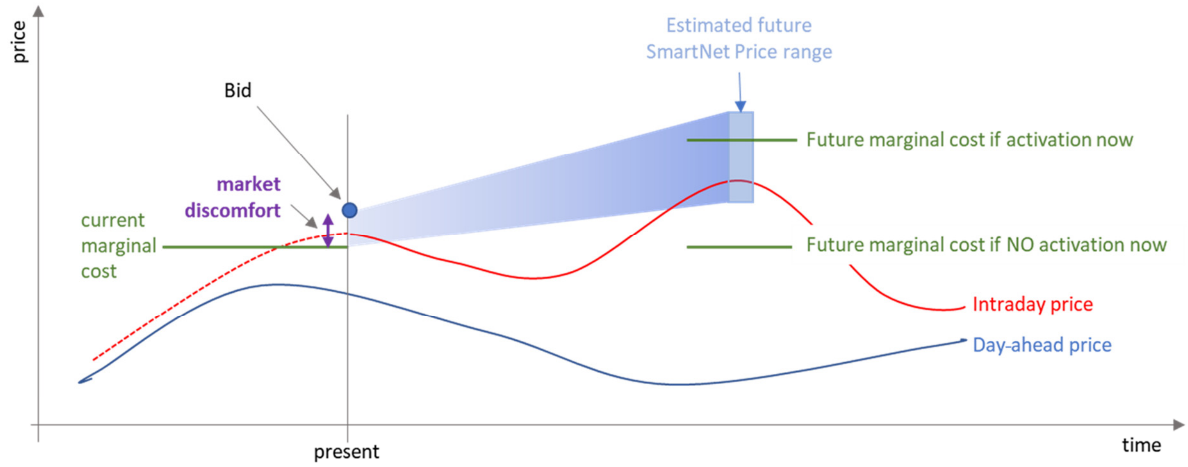

Figure 3.1 Representation of the Market Discomfort Cost

These will be reflected in a market discomfort cost (MDC), which is aggregator and node dependent:

$$c_t^{\text{market discomfort}} = T_{ij} + \omega \cdot RiskPremium, \forall t, \tag{5}$$

where:

- $c_t^{\text{market discomfort}}$ quantifies the market discomfort cost at time step t,
- T_{ij} represents the difference between the estimated/forecasted market clearing prices of the consecutive markets,
- ω is a nonnegative coefficient, $\omega \in [0,1]$, that weighs risk aversion, whereby $\omega = 0$ represents the extreme case of a risk taker, while $\omega = 1$ represents the extreme case of risk aversnes,

- $RiskPremium$ is a function of the next market clearing price uncertinty, current market clearing price uncertinty, bid volume uncertinty, expectation of future activation, etc.

MDC is incorporated in the existing flexibility cost (1), in order to produce a bid in the present SmartNet market, according to:

$$c_{DER,t}^{\text{flex}} = \boldsymbol{c}_{DER,t}^{\text{discomfort}} + \boldsymbol{c}_{DER,t}^{\text{indirect}} + \boldsymbol{c}_{DER,t}^{\text{operational}} + \Delta_{DER,t}^{\text{revenue}} + \boldsymbol{c}_{t}^{\text{market discomfort}}. \quad (6)$$

If a bid that considers MDC is accepted, the additional revenue from MDC should compensate for the opportunity cost received from an activation in the nearby future. In other words, MDC represents an artificial cost that makes the aggregator indifferent between an immediate activation and the one in the future at a (potentially) better profit. If the bid does not consider MDC, the aggregator will act accordingly and place its choice either on selling his flexibility on the intraday market (which pays better than current SmartNet) or waiting for the future SmartNet market auctions.

At this point the behavioral simulation of DERs and aggregators acquires a new complexity dimension. We approach this in two stages:

1. Our simulation environment runs a day-ahead and an intraday price simulation, which delivers as output net-regulating volume and aggregator-specific intraday baseline scenarios that assume a rational and economically-driven optimization of their flexibility.
2. Inside the SmartNet market simulation environment we have postulated a way to cope with this new challenge through a MDC. This new cost parameter is meant to account for the potential inhibition of the aggregators, an element to refrain them from jumping too fast at the first opportunity, disregarding the future value of a limited number of activations available. Hence, MDC refrains the aggregators from offering their flexibility at pure technical cost and introduces a risk-premium or psychological factor that increases the required return from activation, thereby generating the right economic incentive to the aggregator and ultimately DERs.

Let's follow these through a practical example:

- We set an example in a market in 2030 with a significant share of installed renewable capacity. For the sake of illustration let's assume it is predominantly of PV nature and the day-ahead auction is based on highly available resource expectations. Under these circumstances, we expect in the central hours of the day depressed prices due to absence of conventional generation; also this will schedule some flexible consumption in the hour of the lowest price, which is the one with the most relative renewable share in the generation stack, let's say the hour ending 13h (H13).
- Following the day-ahead auction, the intraday market opens. Here, the price for H13 is sensitive to the updated forecasts on cloud coverage at around noon to 1PM. Under the

assumption that the day-ahead PV generation forecast is high (and resulting in low day-ahead prices), the potential opportunity for the DER would come in case of rising prices in the intraday, owing, for example, to unforeseen cloud coverage and therefore lower-than-expected PV infeed. Our DER places its flexible consumption in H13 to buy at a "cheap" day-ahead price. An increase in price represents an opportunity for our DER to resell its cheaply acquired volumes at a profit, thereby scheduling a consumption curtailment in H13. For simplicity, let's assume this is DER's choice at gate closure.

- When considering participating in the SmartNet market, DER's updated baseline is to curtail consumption, and its flexibility is to consume again, i.e. to buy cheap energy. It will consider the option to bid in SmartNet in down-regulation.
- In aggregators' decision to bid, the marginal costs are considered (rebound and other technicalities). For this marginal activation, the number of activation, as well as MDC, will represent one more variable to optimize against. In SmartNet we have proposed to deal with this by incorporating a dummy cost named MDC, which accounts for the following effects:
    - MDC value will increase when intraday prices for future delivery are almost as interesting, or when the market volatility is high. This reduces the probability of activation. However, this does not mean that the aggregator will reject activations, only that it will, at least, require making profit in order to be satisfied.
    - MDC value will decrease when the intraday prices for future delivery are far less interesting, or when the market volatility is low. This enhances the probability of activation, yet it will result in a larger indifference from the aggregator to be activated now or later.

In essence, the MDC works as an opportunity cost, representing the additional revenue of a near-future activation. This consideration brings out two implications regarding MDC:

- it is always non-negative, and
- it is proportional to the higher expectation of the future (individual) activation.

Since different aggregators, just as different people, have different expectations, risk aversion and market information, it is assumed that leaving this MDC flat for every aggregator in every node would not be realistic and would lead the aggregated response from aggregators across the grid to a binary behavior, i.e. they would all switch at the same prices, hence finding large capacity steps. Instead, we opted to using a weighting parameter multiplying the risk premium described above with a randomizer parameter omega ($\omega \in [0,1]$). In this way, each aggregator in each node will have its own risk aversion, while all of them will increase or decrease when volatility fundamentals increase or decrease respectively. In the simulation the omega parameter is assigned to each aggregator and for each node once, and then kept constant throughout the simulation exercise.

4 Overview of Aggregation Approaches and Types of Disaggregation

In the literature, there are different aggregation approaches used for bidding in the electricity market:

- physical (bottom-up) approach (also referred to as the envelope approach in this document);
- traces approach;
- data-driven approach;
- justified approximation approach (also referred to as the hybrid approach in this document).

Each aggregation approach has certain shortcomings – either due to the amount of required data, or due to the accuracy aspect of the modelled portfolio. These are discussed below, with Table 4.1 providing an overview of the references and characteristics of the disaggregation for each approach.

The physical (bottom-up) approach [18], [19] uses the horizontal summation[11] [20], [21], of power calculated for the individual devices. In this approach, it is assumed that the aggregator knows all of the parameters of each individual device and its real-time status (availability, power set points, etc.). The provision of energy by the physical entities in [19], including the onsite generation, EES systems, load curtailment and load shifting, are modelled as aggregated bids and applied in aggregator's self-scheduling optimization problem. The bottom-up approach intends to study the adoption of DERs from the perspective of the physical entities, including the constraints and technical peculiarities for each technology. The physical approach can potentially become hard to implement when many heterogeneous energy resources are included. In fact, different input parameters and constraints have to be defined and represented in the model, where the approximation of generic parameters might not accurately represent the modeled DERs' portfolio. The advantage of this approach is that the disaggregation is straightforward.

The traces approach [22], [23] shares similarities with the physical bottom-up approach. The exception is that it is characterized by load profiles and the cost associated with each of the profiles, rather than by the exact physical DERs' characteristics due to, for instance, confidentiality reasons, prohibitive complexity or insufficient accuracy of the available models. The aggregation is represented by all the possible combinations of feasible profiles of all the devices. While forming optimal bids with only this information is a combinatorial problem that is generally infeasible, forming near-optimal bids is usually feasible. As for the bottom-up approach, the particular advantage of the traces approach is that the disaggregation becomes trivial. When a bid is formed from a particular combination of the feasible

[11] Horizontal summation implies the addition of the bid blocks' energy volumes, while sorting them, according to their bid price, in the ascending order. In other words, the aggregator is offering to reduce or increase the flexibility, in reference to the baseline, at rising cost (see Sections 5.2.4 and 5.5.5, as well as [21] for details).

profiles defined for each device, and the bid is cleared, allocation of feasible profiles to every aggregated device simply means allocation of profiles corresponding to that combination.

The data-driven approach [24]-[26] is based on data and intends to emulate the behavior of a pool of devices. Here, the physical entity and the specific technology is not considered any longer, as the behavior of the overall pool is analyzed. For this approach, the availability of good-quality data is fundamental. Alternatively, the data needs to be simulated. The data is simulated in order to set up the initial input parameters of the aggregated cluster, which later can be modified in order to eliminate the deviation from the real-life data. In [25] and [26], the data-driven approach is applied for predicting the optimal bidding schedule. The data-driven approach does not require any input parameters taken from literature or practical experience, since it is built by using a more accurate level of information in case real data is available. Due to this reason, it needs more input data than the physical approach, which can be problematic in case of data scarcity. This is why such an aggregation approach is not used in SmartNet, since the consumption data elasticity, correlating to the change of the electricity price, is still nonexistent for most of the DERs considered in this project. In contrast to the physical approach, which requires that the DERs' input parameters are known in advance, in the data-driven approach the input parameters, of the cluster being aggregated, are estimated based on the available data. Unlike other aggregation approaches mentioned here, the data-driven approach requires a disaggregation model.

The justified approximation (hybrid) approach [7], [27], [28] uses a single or a limited number of virtual devices in order to represent the entire population of aggregated devices. Such practice reduces the number of individual devices and avoids the large number of input parameters required for the aggregation models. Hence, it can be argued that in the case when a high number of devices need to be aggregated the justified approximation is a reasonable approach. The drawback of this approach is that in the case of heterogeneous devices, the hybrid approach introduces a modeling error, since it represents the entire population of aggregated devices by the parameters of a single or a limited number of virtual devices. A way to reduce this error is to cluster the devices that have similar model parameters, such that there are homogeneous devices in each cluster. A potential algorithm for clustering of the individual devices is the *k*-means algorithm [29]-[31]. As the number of clusters increases, the hybrid approach becomes closer to the bottom-up approach. In the case when the number of clusters equals the number of individual devices, the hybrid approach becomes the physical, bottom-up, approach.

Table 4.1 Overview of different aggregation approaches for DERs

Aggregation approach	References	Disaggregation
Physical	[18], [19]	Straightforward
Traces	[22], [23]	Straightforward
Data-driven	[24], [25], [26]	Model
Justified approximation	[7], [27], [28]	Straightforward

The bottom-up approach was selected as the preferred option due to the lower number of devices, which are being aggregated into each MV node. The number of devices is higher when aggregating into the transmission level node, making the bottom-up approach cumbersome. The aggregation is done into each MV distribution level node separately, as shown in the example of "Node B" in Figure 4.1. This is done due to the fact that the SmartNet market clearing will be done on the per node basis, i.e. nodal pricing is used in the SmartNet market. By choosing the bottom-up physical approach, disaggregation is straightforward, since the devices which bid with price lower than the market clearing price are the only ones being activated. This makes disaggregation models superfluous.

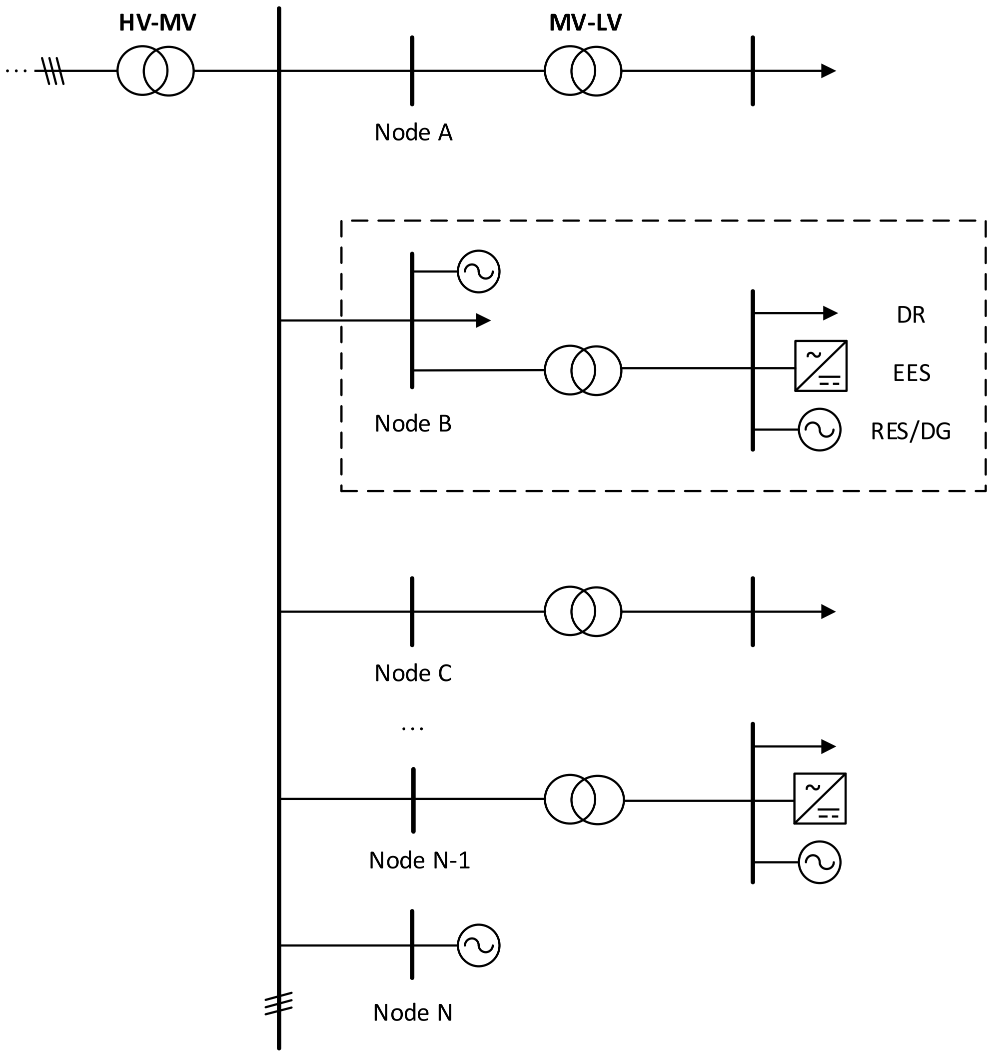

Figure 4.1 Distribution network illustration

5 Aggregation Models

This chapter explains the characteristics of the five aggregation models developed in the SmartNet project. Although the bottom-up approach was selected as the preferred option, as explained in Chapter 4, other aggregation approaches were used in some of the models due to physical characteristics of the aggregated devices, the number of the individual devices being aggregated and the availability of data. This is summarized in Table 5.1. Each model gives the practical characteristics of the aggregated DERs and defines the quantity and the cost of the active power flexibility. The models also define the bidding strategy and the type of the bids submitted to the market.

Table 5.1 Aggregation approaches used for aggregation of different DERs

Aggregation Model	Aggregation approach
Atomic Loads	• Traces
CHP Units	• Physical
TCLs	• Physical • Justified approximation
EES Units	• Physical
Curtailable generation and curtailable loads	• Physical

The unification of symbology, and units of measurements, is applied between the five aggregation models, making sure that the models are uniform from this aspect. The main indices that are used in the deliverable, and the corresponding units of measurement, are shown in Table 5.2, unless otherwise specified later in the text.

Table 5.2 Unification of symbology and units of measurement among the aggregation models

Quantity	Symbology	Units of Measurement
Active power	• P	• MW
Reactive power	• θ	• MVAr
Energy	• E	• MWh
Heat transfer	• Q	• MW
Time	• t	• h
Temperature	• T	• K
Cost/price	• c	• €/MWh

5.1 Atomic Loads

5.1.1 Introduction and Definitions

This section describes aggregation models for the flexibility offered by atomic loads. Atomic loads have a fixed load profile which approximates the power consumption of a device, or the total power consumption of a batch process, with different machines working in a scheduled sequence. Atomic loads can only provide flexibility by:

- Delaying or advancing the starting time of the load or process and
- Replacing the scheduled load profile with an alternative profile before it starts.

Atomic loads differentiate themselves from more general shiftable loads. Once started, atomic loads cannot be paused, interrupted or altered "on the fly." This prevents the aggregator from modifying the load profile of an already activated device, which is a realistic assumption for devices which follow predetermined cycles after activation. It is assumed that power consumption does not change much between different uses[12]. This model is also suitable when the nature of the task being performed requires strict adherence to a selected fixed power profile. Different operation modes can be represented by different power profiles. The choice must be made before the task starts, and it cannot be changed afterwards[13].

The work in [22] and [23] focuses on shiftable atomic loads (interruptable and non-interruptable). The work in [32] deals exclusively with interruptible shiftable loads. In [22] and [23] the loads are taking constant power for all time steps. In [32] the author is interested in the total accumulated energy use. In the description of atomic loads given in this section, the load profile is represented by a vector of power consumptions for every time step, discretized at a given time resolution. This is a more general representation of the power profile and it becoming more common thanks to the increasing availability of high-resolution power profile data [33], [34].

5.1.1.1 Shiftable Atomic Loads

Atomic shiftable loads provide flexibility purely by advancing or postponing their scheduled times of activation. The load activation can be shifted by an integer number of time periods. Negative offsets indicate a shift towards an earlier time period, and positive offsets indicate shifts towards a later one. The flexibility for atomic loads can thus be expressed as a finite set of possible integer offsets. Shifting atomic loads forwards or backwards in time will typically induce changes in costs. Depending on the particular

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[12] For instance, it is assumed that the power consumption of a dishwasher is approximately independent of what is inside the machine.

[13] For instance, an industrial oven can have settings allowing a slow burn or a quick burn, with carefully adjusted temperature set points. In this case, changing settings after the task is started would result in a damaged product.

type of the shiftable load this cost can be composed of operational costs, as in the case of industrial processes, or discomfort costs, as in the case of wet appliances, both explained in Section 2.4.7 in the deliverable D1.2 [4].

Figure 5.1 shows an example of a shiftable load.

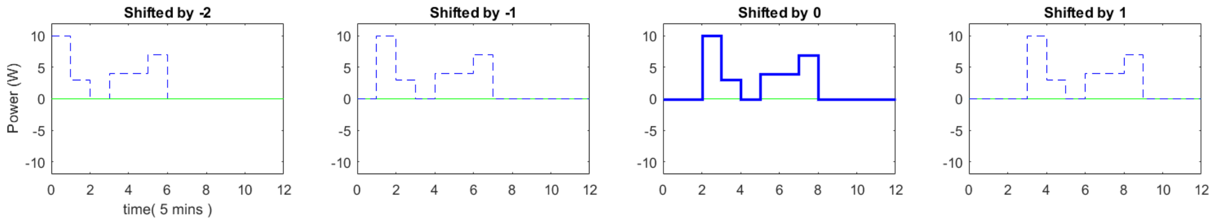


Figure 5.1 Example of a shiftable load

5.1.1.2 Alternative Atomic Load Profiles

A set of different load profiles can be used to represent the power consumption of a device that has different operation modes available when performing the same task. An industrial oven, for instance, can have one quick burn and another slow burn mode. Each operation mode results in an alternative power consumption profile. If both of them are acceptable to the end-user, the aggregator can use that choice to provide flexibility. Instead of initiating the profile associated with the default operation mode, one of the available alternatives can be initiated instead. As an example, the aggregator may decide on starting a quick burn when increased power consumption is requested by the SO.

The alternative modes of operation are not required to be completely equivalent; there is a trade-off between energy consumption and different levels of quality or comfort derived from the task associated with the load. The different costs will quantify the desirability of one program against the other. Each of the alternative modes of operation will be represented by its own power profile curve and costs.

Note that in order to handle shiftable loads as a particular case, the alternatives of an atomic load are allowed to have different starting times. In contrast with the more restricted class of shiftable loads, it is possible for the total energy consumption to be different. The power profiles of the alternatives can present different shapes, as it is shown in Figure 5.2.

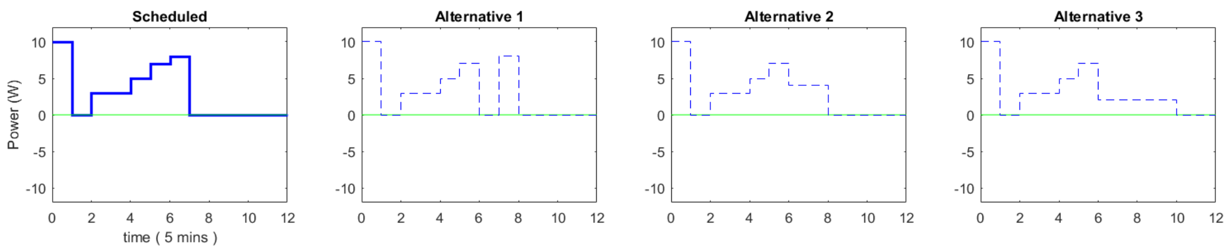


Figure 5.2 Example of alternative load profiles

5.1.1.3 Sheddable Atomic Load Profiles

Atomic load shedding can be also regarded as a particular case of alternative load profiles, consisting of two alternatives: one power profile resulting from the normal activation of the load or a null power profile, which results from the load activation being cancelled. Figure 5.3 shows an example of a sheddable atomic load.

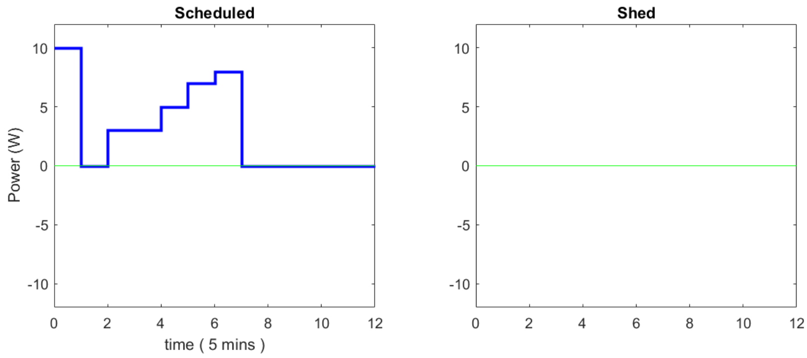


Figure 5.3 Example of a sheddable atomic load profile

Conversely, the default can be assumed to be the null power profile with zero cost – indicating that a given load will not run, and the alternative can be a given power profile, associated with a negative cost to run. This would allow the modelling of opportunistic loads, which would be willing to pay in order to run. These loads would run only at times when it would be useful to balance the system. They would be triggered depending on market conditions.

5.1.2 Examples of Flexibilities Provided by Atomic Load Profiles

Different from the other types of DERs, atomic loads considered individually look quite rigid and it might seem counter-intuitive that they can be aggregated and offered as a source of flexibility. The following section shows some examples of the flexibility obtained by departing from the scheduled program of a single atomic load. This will be then compared with the flexibility resulting from a group of aggregated atomic loads.

5.1.2.1 Examples of Flexibilities Provided by Single Atomic Load

When extracting flexibility from atomic loads, a new load profile needs to be subtracted from the scheduled load profile.

5.1.2.1.1 Shiftable Atomic Loads

In this example, the default profile is the one designated as "shifted by 0," in the third column in Figure 5.4. By default, the profile will run as scheduled and provide zero flexibility, as shown in the bottom row of the third column in the same figure. In that case, the load will consume all the energy corresponding to

the different time steps. If the load is instead shifted by -2, -1 or advanced by 1, this will induce a change in the power profile that will reduce the load at certain time slots while increasing the load in some other time slots. The flexibility profiles, on the bottom part of Figure 5.4, are the differences between the shifted profile and the original profile ("shifted by 0").

In general, the resulting flexibility profile will have inter-temporal constraints ranging over a number of time steps larger than the load profile length, as can be seen in Figure 5.4. Another noteworthy aspect is the fact that these flexibilities, unless shifted beyond the time horizon, will always satisfy integral constraints.

Integral energy constraints arise when exactly the same amount of energy must be delivered to the device or process which is producing the load. When compared to the default power profile, there will be steps of negative flexibility (when the load is increased), compensating for any time steps of positive flexibility (when the load is reduced). There are many possible profiles which satisfy the same energy constraint, and shifted profiles are one particular case.

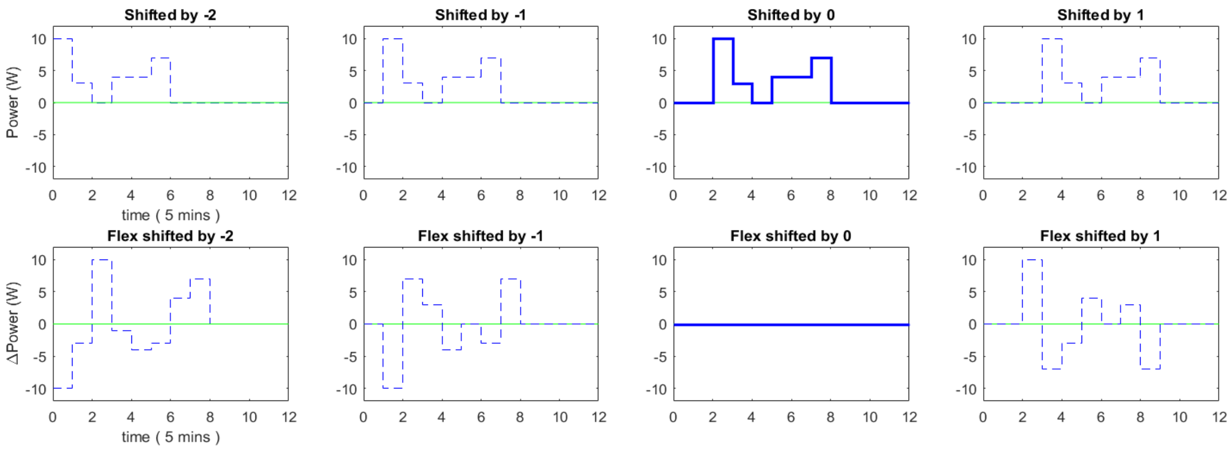


Figure 5.4 Flexibility from shifting an atomic load profile

5.1.2.1.2 Alternative Atomic Loads

Figure 5.5 shows an example of alternative flexibility profiles generated by alternative loads. Graphically the flexibility profiles look similar to the previous case, but the profiles are not limited to be shifted versions of the original profile. They also do not need always to satisfy integral constraints. If integral constraints are not satisfied, a different amount of energy may be delivered to the device or process generating the load.

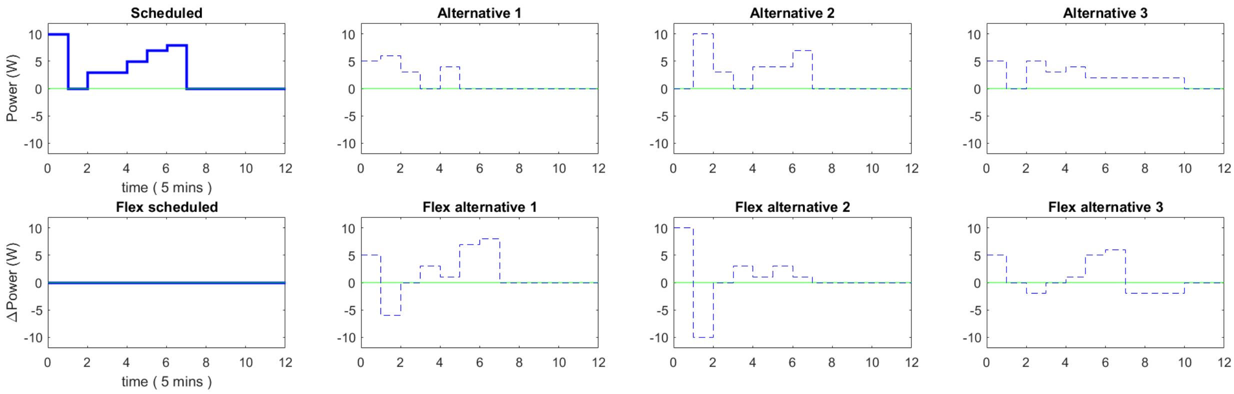


Figure 5.5 Flexibility from alternative load profiles

5.1.2.1.3 Sheddable Atomic Loads

Figure 5.6 displays the flexibility obtained by shedding a load. This case is the most intuitive, since the released flexibility has the same shape of the scheduled load.

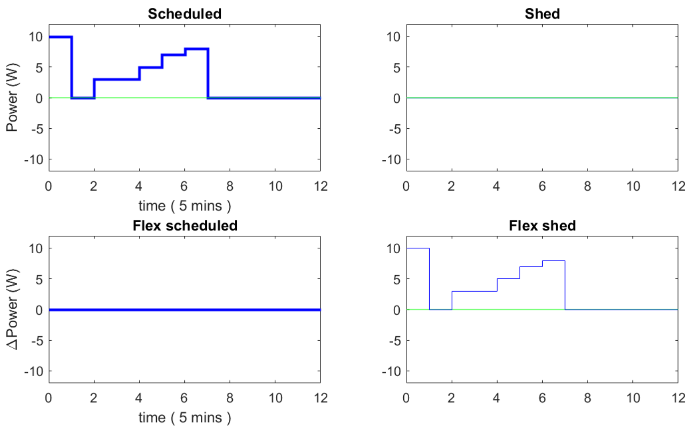


Figure 5.6 Flexibility from shedding load

5.1.2.2 Examples of Aggregated Flexibility Provided by Atomic Loads

In this section, it is described how the flexibility offered by atomic loads can be aggregated and shaped into more desirable flexibility profiles. The panes in Figure 5.7 show six different devices that are represented by a set of alternative atomic loads. Time shifts and shedding are all processed by the aggregator as different alternatives. The different alternatives face different costs, as described in Chapter 2, associated with different operational, indirect or discomfort costs. The costs can be assumed to be relative or absolute. In case of relative costs, the preferred alternative is always assumed to have zero cost. In Figure 5.7, costs are assumed to be absolute, and the preferred alternative of the first load is assumed to be the choice with a minimum cost of 3.1.

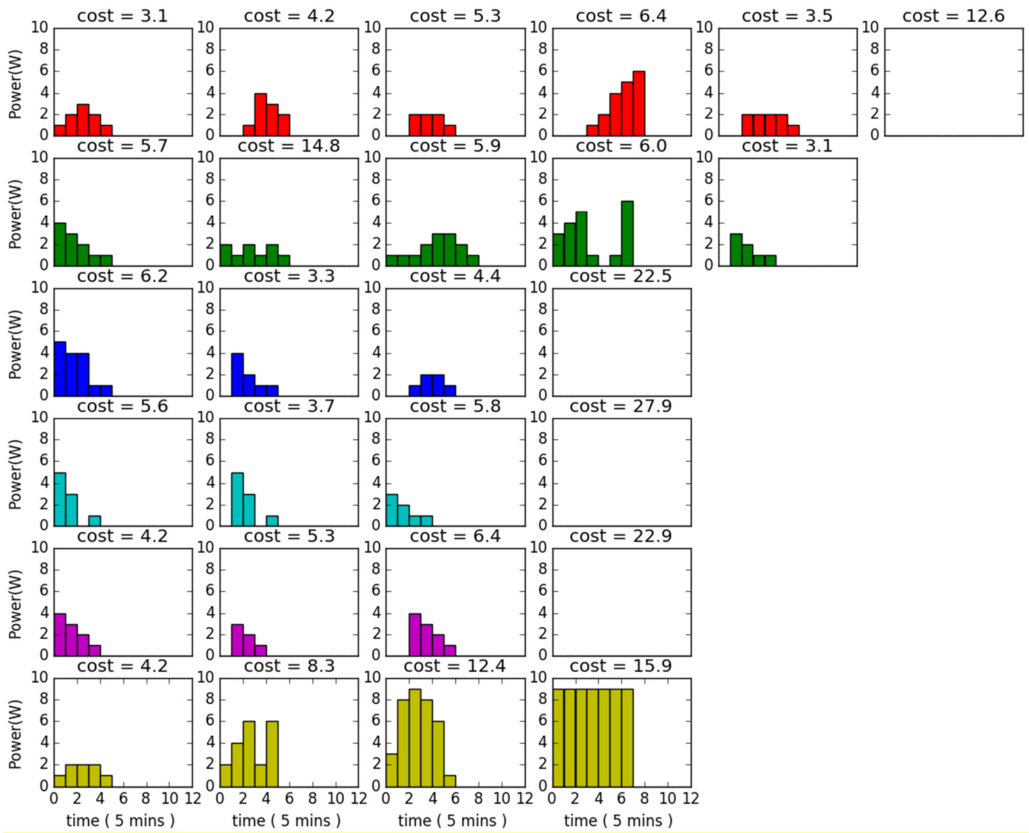


Figure 5.7 Six different aggregated flexibility profiles of alternative atomic loads

As seen in the previous section, the departure from schedule of a single load typically generates a flexibility profile with many fluctuations.

The aggregator, at the other hand, is able to combine the individual flexibilities in such a way that a more suitable flexibility profile bid can be submitted to the proposed market. The offered profile can be influenced by price estimates or by bid limitations. In any case, if the bid is accepted, the aggregator will update the list of loads, which are scheduled to run in the next time slot. All the loads that are not activated in the next time slot are free to participate in the subsequent offers of flexibility, until eventually the load proceeds to its scheduled program selection and activation.

The rolling time window is a convenient mechanism to align future imbalance forecasts with flexibility offers defined for multiple time steps. However, these multiple time step bids are more complex to the market clearing block, and its number may be limited depending on performance constraints. Also, the more distant the time slot, the bigger the uncertainty. The first time slot of the time window is the most urgent and it has the least uncertainty regarding the sign of the imbalance. Therefore, it usually has the largest impact on the decision of a flexibility buyer to accept a bid or not. This is the reason for building flexibility bids concentrated as much as possible on the next time slot, with a positive or negative peak.

Figure 5.8 illustrates a toy example that builds a flexibility bid with a perfect peak formed with aggregated atomic loads[14]. The baseline power profile is the starting point for both columns. In the first column, a reduced power profile is produced by switching to selections that present higher operational costs. The same happens in the second column. At this time, a more power-intensive alternative is chosen for the second load.

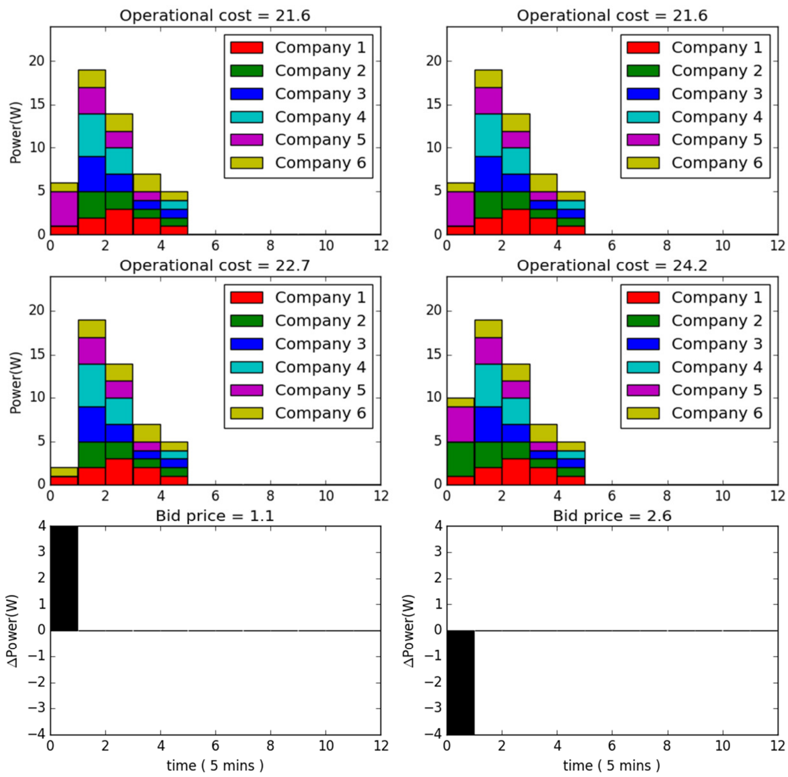


Figure 5.8 Aggregated flexibility profiles of atomic loads consisting of a single peak

This aggregated flexibility profile consisting of a single peak is simple enough to be submitted as a *non-curtailable unit bid* to the market block. The bid price is the added cost that the aggregator's clients would have to face in order to change schedule and deliver on that bid. For the bid in the left column, the aggregated load is reduced for the next 5 minutes, and 1.1 would be the minimum price for returning this energy back to the grid. For the bid in the right column, the aggregator is proposing to increase its offtake.

5.1.2.3 A More Realistic Example of Aggregated Flexibility

Figure 5.9 shows a more realistic example with 30 different loads and 4 alternatives each. The problem is solved using IP – to be detailed in the next sections. The problem is small and it was solved

[14] It is necessary in that case to use sheddable atomic loads or alternative atomic loads to avoid the energy rebound.

almost instantaneously by CPLEX. The flexibility bids offered are not perfect peaks, but display a small tail when compared to the peak size.

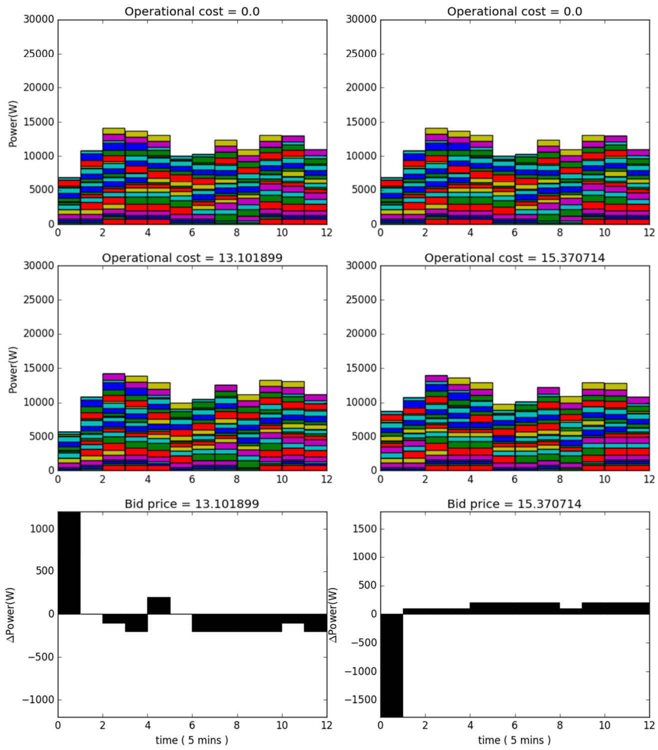


Figure 5.9 Aggregated flexibility of 30 different loads and 4 alternatives each

5.1.2.4 Data Source

The data used for this particular example is random. The atomic loads are either zero or constant, running for some minutes, then stopping and starting again. That simulates the short cycles of operation of some real loads, which fit well into the maximum time frame considered by the SmartNet market block. Four alternatives were added for each load – advancing the task 5 minutes, keeping the scheduled time or postponing the task for 5 or 10 minutes. Figure 5.10 represents one of these load profiles.

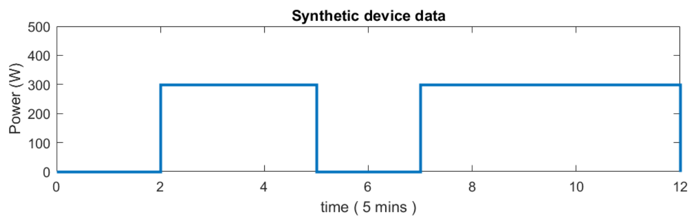


Figure 5.10 Synthetic device data

5.1.3 Modelling Approach for Aggregating Atomic Loads

The atomic loads aggregator is an example of the aggregation by the traces approach, described in Chapter 4. The traces approach is suitable for the modelling of devices which cannot modulate their power consumption in an independent manner for each time slot. Once the starting time and the mode of operation is defined, the power consumption of the device follows a predefined profile. In this restricted class, the flexibility provided by a single device results in large rebounds, as shown in Section 5.1.2.1. The atomic loads aggregator can manipulate other incoming loads in a coordinated manner in order to keep the power rebound limited, as illustrated in Section 5.1.2.3.

5.1.3.1 Practical Considerations

The traces approach employed by the atomic load aggregator allows a more pragmatic approach to be assumed when modeling the flexible devices. Instead of forming an inner model for the devices and finding its parameters, it focuses on the collection of approximate traces from the most important loads. These traces do not need to be collected on-site, being very similar for well-functioning machines of the same model.

It is assumed that the flexibility bids are formed for the next hour, discretized in a 5 minute time resolution. These time window parameters will be adjusted if needed according to the simulation scenarios in Task 4.2. In any case, it will be assumed that the aggregator handles any rebound effects spilling outside this market clearing time frame. The management of the aggregator imbalances accumulated after successful bids creates some difficult problems that would require the use of more sophisticated planning models for the aggregator. For the purposes of the SmartNet simulation, it will be assumed that these accumulated imbalances will generate aggregator losses that need to be included in the bid prices.

5.1.3.2 Flexibility Model

5.1.3.2.1 Numeric Representation for the Individual Shiftable Load

Loads and flexibility costs are discrete and ad hoc, and the method of their calculation does not need to be known in detail. For instance, this discrete data could be constructed from the wet appliance devices (see Table 31 in Section 8.7 in the deliverable D1.2 [4]). The loads are represented by their expected power profiles for the incoming hour, and each hour is represented by 12 time slots, assuming a five-minute discretization is used:

$$P^{i,j}[t] = [p_0^{i,j}, \dots, p_{11}^{i,j}] \tag{7}$$

where:

- i represents the load index and,
- j represents the selected alternative, including shedding and shifting,
- t represents the next hour, containing twelve five-minute time slots.

Flexibility costs C_i^j are always expressed for the whole profile, and not per time step.

The ad hoc flexibility costs can be assigned by sophisticated planning-and-scheduling systems, as described in Section 2.4.7 in the deliverable D1.2 [4], or it could be simply defined by a time window, where a load associated with some task is assumed to be able to delay its starting time for 5 or 10 minutes without increasing its costs.

The default selection is indicated by $\tilde{j}$ and the new selection by j. The flexibility released by changing the selected operation mode for load i is given by the vector $P^{i,\tilde{j}} - P^{i,j}$.

5.1.3.2.2 Model for Aggregated Alternative Loads

The aggregated bid is formed by solving a very simple optimization problem, using IP. The baseline energy profile is given as an input. It usually results from selecting those programs with the smallest operational costs $\tilde{C}$ or following a more sophisticated energy-aware strategy at the day-ahead market (DAM). In any case, the bid formation analysis starts with a base power profile and its base cost:

$$\tilde{P}[t] = \sum_i P_t^{i,\tilde{j}_i} \tag{8}$$

$$\tilde{C} = \sum_i C^{i,\tilde{j}_i} \tag{9}$$

Later the allocation resulting from a change in scheduled program is defined in terms of Boolean indicator variables s_i^j, assuming value one for the proposed scheduled alternative and zero for the others. For a new load selection j_{new}, only $s_i^{j_{new}} = 1$ and $s_i^j = 0$ for all $j \neq j_{new}$.

Since each atomic load has to be assigned to one of its possible alternatives, j_{new} is a function of i. This mapping is given implicitly by the selection variables s_i^s. With this, it is possible to calculate the released flexibility as a function of the new selection:

$$P_{new}[t] = \sum_i P_t^{i,j_{new}(i)} = \sum_{i,j} P_t^{i,j} \cdot s_i^j \tag{10}$$

The flexibility profile to be offered is given by the vector:

$$\Delta P_{flex}[t] = \tilde{P}[t] - P_{new}[t] \tag{11}$$

This amount is positive when the aggregator is returning unused energy to the grid and negative when it demands more energy in relation to the base allocation. It is a function of the selection variables – which are omitted for simplicity.

One possible optimization problem, which models the bid formation, faced by the aggregator of alternative loads is the following:

$$max\ \Delta P_{flex}[0] \tag{12}$$

Such that

$$\sum_j s_i^j = 1, \text{for all loads } i \tag{13}$$

$$\left\|\Delta P_{flex}[t]\right\| < \varepsilon, \text{for all } t > 0 \tag{14}$$

$$s_i^j = \{0,1\}, \text{for all loads } i \text{ and alternatives } j \tag{15}$$

An objective function in equation (12) is defined to form what the aggregator considers to be a 'good' bid. In that case, it is maximizing the positive peak in the first time slot. It is assumed that the time slot indices start from zero.

The second line, equation (13), guarantees that one alternative must be selected for each load – shed loads also receive their own alternative with corresponding cost.

The third line, equation (14), represents a simple tail-management scheme – the aggregator will look for bids that keep the rebound effect limited to a given threshold ε.

This simple optimization problem can be refined later when more information is known about what kind of bid shapes are preferred by the flexibility buyer. The aggregator would then be searching for the best bids it can make concerning its profit. A change of selected alternative will incur costs C_i^j which can be aggregated into C_{flex}:

$$C_{flex} = \sum_{i,j} s_i^j \,.\, C_i^j \tag{16}$$

C_{flex} can be later compared to $\tilde{C}$, which is the reference cost of the default schedule, in order to form bid prices.

5.1.3.2.3 Modulating Aggregated Loads to an Indicative Price Signal

As hinted by the previous section 5.1.3.2.2, when the market design provides an indicative price signal or, alternatively, when the aggregator has some sort of imbalance forecast, it is possible to search for the best possible flexibility profile to offer to the aggregator.

When offering a flexibility block constraint (14) needs to be dropped, since we want the system to offer flexibility at different time slots. A first model is displayed below.

$$\max_t \lambda[t]\ \Delta P_{flex}[t] \tag{17}$$

Such that

$$\sum_j s_i^j = 1, \text{for all loads } i \tag{18}$$

$$s_i^j = \{0,1\}, \qquad \forall i,j \tag{19}$$

Besides requiring indicative price information, one difficulty with this model is that a whole block of flexibility will be offered in the current market iteration. If prices are low at the beginning of the time window, it would be advantageous for the aggregator to start as many loads as possible.

The previous model, however, does not explicitly formulate waiting loads and does not explicitly enforce causal constraints on arriving loads. In fact the previous model assumes that all loads in the time window are available to be anticipated, when necessary.

An improved model is described in [35] that is more suited to form a block bid given an indicative price signal. The model manages the buffer of waiting loads and enforces a maximum delay on load activation.

In a sample block bid is displayed for a large cluster of wet appliances. The aggregator expects 200 appliances to join at every time slot. Every load depending on its arrival time is allowed to wait up to 6 time slots.

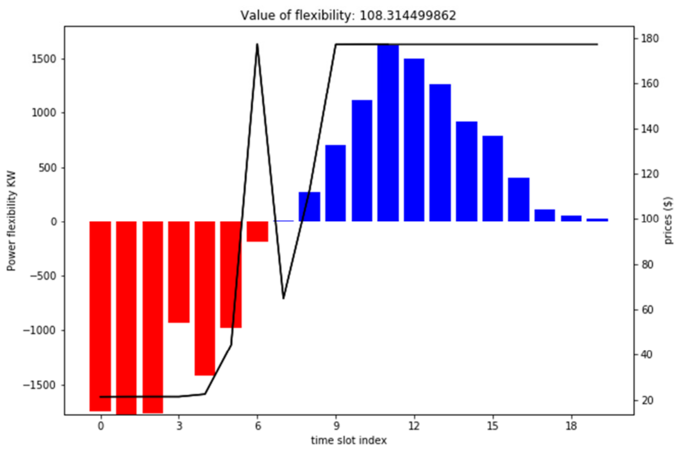


Figure 5.11 Flexibility block modulated by price information

5.1.3.3 Flexibility Cost Model

The costs C_i^j are applied to the whole selected profile i when the alternative program j is selected. Despite the differences between aggregation techniques, the same flexibility cost breakdown defined in Chapter 2 also applies to atomic loads:

- Operational cost: related to the rescheduling of tasks or program changes. Those costs depend mostly on the physical and operational details of the process, for which no assumptions are made.
- Indirect cost: This is better handled at the aggregator level, and relates to the cost of handling the departure from the baseline allocation in order to provide a bid for the immediate imbalance, in particular what lies outside the one-hour window. Departures from the base allocation can propagate with time and they need to be settled later, or compensated by the intraday market actions, or by another load activation.
- Discomfort cost: Since there are no common variables, such as temperature, to observe, it is assumed that the discomfort generated from a change in the scheduled atomic load is dependent on the device type and related to its change of schedule. Hence, it is integrated as an “ad hoc” cost.
- Aging cost: There are no extra aging costs resulting from the successive activations of flexibility, since the flexibility will be provided by the activation of loads, which were already scheduled to run. This is a factor, which contributes for this class of devices to offer flexibility at a low cost.

5.1.3.4 Market Variables and Bidding Strategy

The markets considered in the SmartNet project differ in time granularity and in the complexity of the supported structure of the bid formats.

As mentioned in the previous section, the cost of providing the aggregated flexibility to the market will depend also on the bid formats which are supported[15]. For instance, deferrable bids allow shiftable loads to be expressed in a straightforward way, all-or-nothing bids provide direct support for flexibility offers with multi-period rebounds, and alternative bids will increase the utility of aggregated alternative load flexibility. Nevertheless, the aggregator aims to construct the most useful flexibility bids possible, even in markets where only the simplest bids are supported.

So far, it has been assumed that both of the flexibility bids shown in Figure 5.12 are equally desirable. Unless the aggregator has some way to observe the market from the flexibility buyer side, it can only

[15] Qt-bids, all-or-nothing, exclusive, alternative, deferrable.

guess what is desirable and how much a particular shape is worth to the flexibility taker. The alternative would be to make heavy use of the most complex bid types, delegating to the market clearing algorithm to choose from a large number of alternative bids.

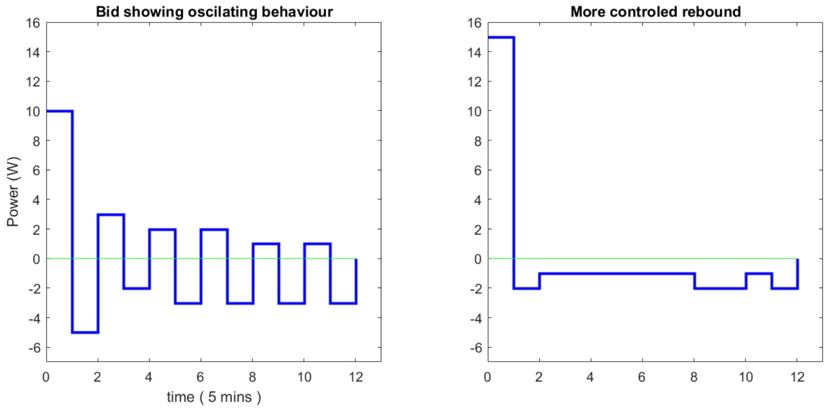


Figure 5.12 Flexibility bids

In a realistic demand-response application, the aggregator needs to manage additional details concerning the pool of distributed resources. The aggregator is responsible for enrolling and qualifying suitable customers, measuring their response to a requested change of schedule, bidding for the pooled energy in the DAM and implementing different kinds of schemes that allow its customers to participate indirectly and profit from the energy markets.

As with any company, the objective of the aggregator is to operate profitably. When planning for the DAM, the aggregator solves its own problem, scheduling its participant loads in the most efficient way, and forming an *optimal participation schedule* [19].

The DAM planning will not be modeled in the context of the proposed flexibility market in the SmartNet project, but the aggregator needs to make a more complicated decision at each time step. The aggregator, as a decision-maker, must find a profitable policy when to offer its pooled flexibility (i.e. now or later), and at what price. The profits of the aggregator are composed of the revenue it receives from its flexibility bids minus the costs incurred by the participants' departure from the scheduled profile.

The participants DERs pass on their own flexibility costs to the aggregator, but other costs such as the indirect costs may only appear at the aggregation level. The contract between the DER owner and the aggregator is usually much simpler than the contract between the aggregator and the energy supplier. While exposing DERs to real-time pricing is one possibility, there are challenges involved with its adoption [36], especially for the residential customers.

As a compromise between these observations and what can be included in the simulation, the cost of activating a flexibility bid is defined by the atomic load aggregator as the cost of activating the alternative load profile minus the cost of activation of the scheduled profile. That approach is consistent with the flexibility cost formula described in Section 2.3.4 in the deliverable D1.2 [4], and Chapter 2 of this

document. A non-curtailable unit bid[16] (NC unit bid) can be formed by having the following bid price, calculated after the optimization problem is solved using IP:

$$C_{flex} - \tilde{C} \tag{20}$$

An interesting line of research that could be explored is the formation of bids composed by disjoint sets of rescheduled devices. That would allow the formation of a non-curtailable Q-bid[17] (NC Q-bid), which is a summation of the disjoint unit bids[18].

Notice that if the same device participates in more than one bid in the current time step, those bids need to be exclusive – they can be all offered with their respective prices, but only one can be accepted.

However, nothing prevents the same device to participate in multiple bids at different time steps, if this device is not rescheduled to run in the next time slot. The device can be tentatively rescheduled many times before its actual activation. This activation can be the outcome of a rescheduling, required after the acceptance of a flexibility bid in which that device participated, or it can simply follow the default schedule of the device.

5.1.4 Iterative Flexibility Trading

The aggregator attempts to formulate possible flexibility bids every five minutes. Some of them are rejected, some are taken, and the aggregator has to manage what remained.

When the bid is accepted, the devices that participate in it can be split into two groups. There are devices that are required to activate in the next time step and others which are also part of the bid, but that were rescheduled in order to modulate the rebound of the first group of devices.

This implies that part of the future flexibility of the pool will be committed to solving imbalances coming from the accepted bids in the past. However, it is an ongoing assessment, and once the estimated imbalances are reduced, the same load can be included in the subsequent bids if there is still time before its deadline.

Some of the aspects faced by the aggregator when it formulates iterative offers throughout the day can be seen in Figure 5.13. The current time window is shown between the red bars.

Black loads represent loads that were already activated – some were rescheduled, others just followed their default schedule. Some were replaced by an alternative with a different profile. Some of them have not finished yet, but in any case, there is no flexibility left once they are activated. The blue loads at the bottom illustrate the opposite situation – these loads represent those that cannot be advanced into the

[16] Non-curtailable unit bid represents a pair of quantity and price that does not allow for the fractional acceptance of the bid. The bid is either fully accepted or not [2].
[17] Non-curtailable Q-bids represents a group of independent non-curtailable unit bids [2].
[18] The term “non-curtailable” is omitted from now on, since the atomic loads are not capable of offering curtailable flexibility.

current time window. These loads do not need to be considered when the aggregator solves its current bid formation problem – this has a very positive computational impact. Only the loads indicated in green are considered at the current time step, with all its alternatives. The small red profile at the bottom displays the accumulated imbalances that were not absorbed by the accepted bids.

The green and black curves at the bottom of Figure 5.13 show the nomination before and after the successive flexibility offers. The green curve keeps changing at every iteration. Any imbalance forwarded in time can still be modified or even included in future bids. The consolidated imbalance at the end of the day will be settled by the usual mechanism of imbalance tariffs.

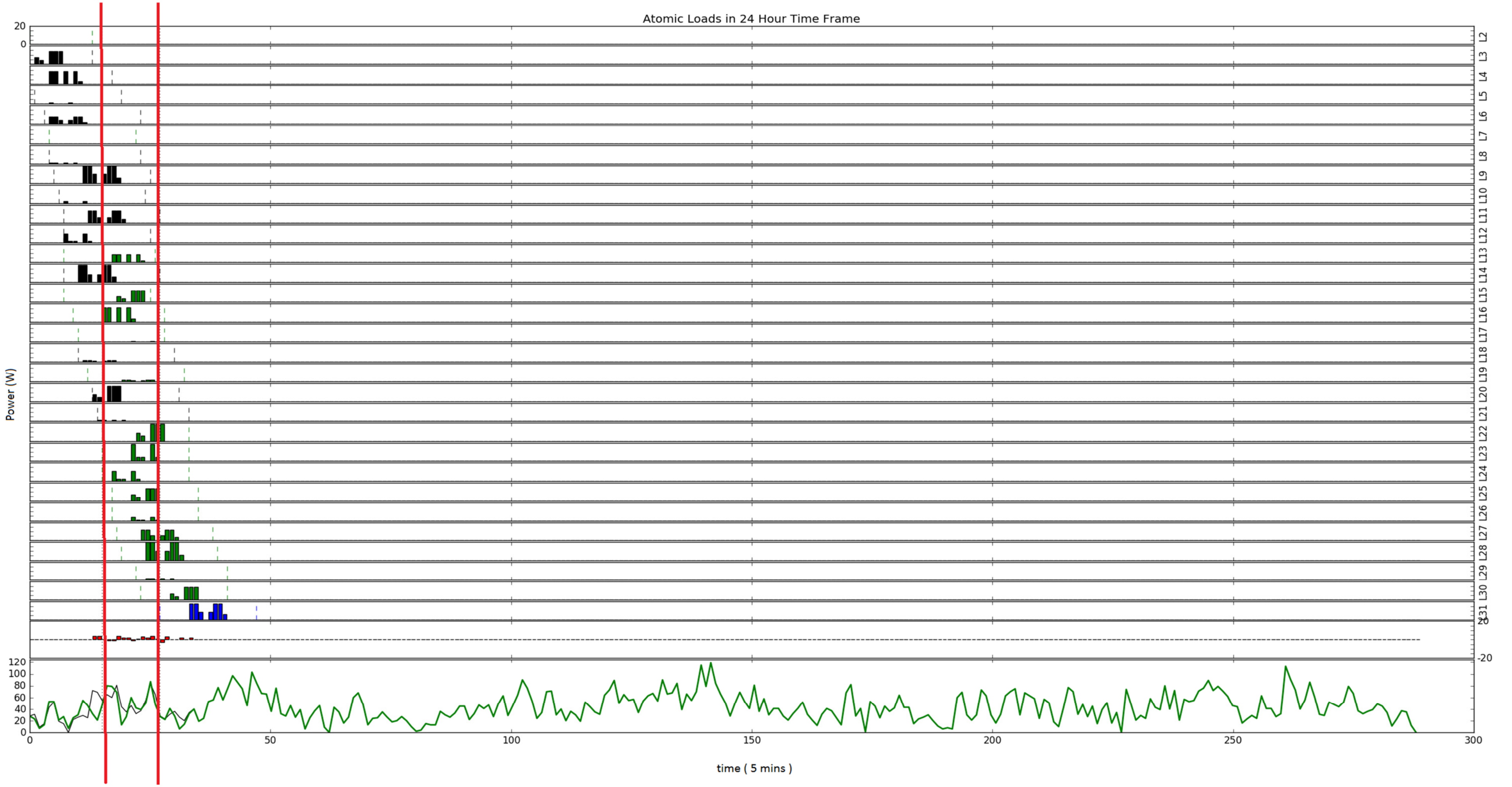


Figure 5.13 Example of aggregators' iterative flexibility offers

5.1.5 Discussion

The synchronized rescheduling of atomic loads is capable of producing not only flexibility bids, but also exhibits some interesting profile shaping capabilities.

In the current market framework, the atomic loads aggregator is capable of calculating a minimum acceptable price for each bid, sufficient to cover the total cost of an eventual change of schedule. This seems to be sufficient and in line with the objectives of the proposed market. When an indicative price signal is available, the aggregator is able to formulate a block bid which maximizes the estimated market value of different flexibility profiles.

The calculation effort for the selection of the loads involved in the next bid is not prohibitive, although further investigation has to be made in Task 4.1 to check its scalability. This approach makes the disaggregation problem trivial.

There are a number of directions where this work could be improved, such as determining a disjoint set of bids and modeling a better real-time behavior of the aggregator throughout the day, finding an optimal or a good-enough policy that follows a profit-maximizing strategy for the aggregator.

The exploration of this more complicated problem is dependent on information not available at this stage. The value of flexibility could also depend on the different times of the day, in the same manner as imbalance tariffs.

The proposed cost of aggregated flexibility absorbs the individual costs outlined in Section 2.3.4 in the deliverable D1.2 [4], and Chapter 2 of this document. Some of the components of the individual costs present challenges for a simulation. It is hard to come up with realistic estimations for operational costs and discomfort costs when the deviations are large, but it is to be expected that these costs should be reasonably low if the alternatives do not change too much for the user, as it happens with a load that is postponed for 5 or 10 minutes.

In a more realistic simulation, deviations would occur for many other reasons, such as the devices not running in their scheduled time. The aggregator would try to keep this cost managed throughout the day while collecting revenue from the flexibility offers. This brings the choice of using part of its flexibility to correct for accumulated imbalances. There seems to be a close connection between the proposed flexibility market and the more rudimentary imbalance tariff system.

A final aspect specific to atomic loads is that the same load can actually have more than one non-urgent reschedule before its activation. The cost of rescheduling included in the bid could actually be recouped by a subsequent reschedule. These are more complex effects arising from iterative trading that could affect bid prices.

5.2 Combined Heat and Power Units

This section describes aggregation models for CHP units for the aggregator's bidding strategies. The proposed aggregation models presented in this section are individual CHP physical models, which have already been defined in [4]. These models describe the energy and heat generation for consumption by using a physical representation of their thermal behavior and states. The physical models describe the energy and temperature as a function of the chemical reaction produced in a CHP, and their environments (heat and electricity losses, reactive power and such). The operation and set up/down costs are also being considered.

The following list summarizes some important aspects to be remarked about the CHP aggregation models described, which will be better described in the following sections.

1. Due to the dependence on performing other tasks, such as heat production, CHP plants are often must-run plants, which generate power at every electricity price level, representing an inflexible capacity part in the system. However, if the heat storage system is modeled, the CHP plants will reduce the must-run capacity, giving certain flexibility to these plants [37].
2. The power generated in the CHP can be separated in two types: electric power and heat. The aggregation model needs to estimate which amount of each power is required for every time step.

5.2.1 Practical Consideration

The bottom-up modelling approach assumes that the aggregator knows all the parameters of each CHP plant. By knowing this, the aggregator is able to calculate the flexibility and corresponding marginal cost of each CHP, by using the flexibility model described in the following section, and to sum them in order to obtain the aggregated flexibility versus bid price.

This modelling approach is based on the possible knowledge of the plants parameters, such as the chemical power (plant input) and the heat capacity state, further explained in Section 5.2.2. In addition, the models take for granted the heat storage monitoring, with a communication between the plant and the aggregator faster than the market periods, since the models would predict the behavior of the CHP for the time period where no real-time data is available. In this way, the aggregator would obtain periodically the dynamic data to feed the models and correct the model parameters using model-fitting techniques.

Since this deliverable serves the purpose of defining the models of the aggregated flexibility to be simulated in WP4, the practical implementation of the monitoring and control mechanisms are not discussed.

5.2.2 Flexibility Model

5.2.2.1 Individual CHP Model

This section provides a model for CHPs based on the generic model developed in [4]. The model, shown in Figure 5.14, describes the simplified model of a CHP plant which consists of a CHP generator and the heat storage. The CHP plant has a single combustion and produces two types of energy: electric, which goes directly to the grid, and thermal (heat), which goes to the heat storage in order to wait for heat demands. The CHP generator transforms the chemical energy into electric and thermal energy. The internal behavior of the CHP generator is outside the scope of the SmartNet project, so its internal description is not provided.

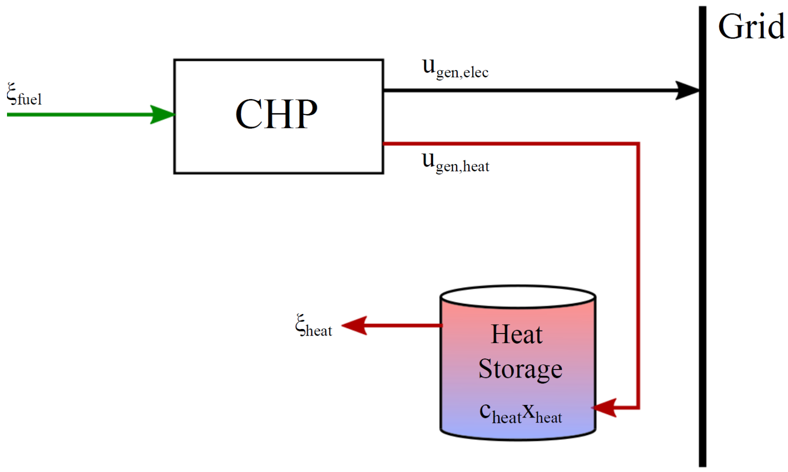


Figure 5.14 Diagram of a CHP plant, presented in [4]

The parameters involved in this modeling are the following:

- $\xi_{fuel,t}$ is chemical power (input to the CHP) at time step t;
- $u_{gen,elec,t}$ is active electric power (from CHP to Grid) at time step t;
- $u_{gen,heat,t}$ is heating power (output of the CHP) at time step t;
- ξ_{heat} is heating power demand (output of the Heat Storage);
- $\eta_{gen,total}$ is CHP total efficiency (heat and electricity combined);
- $\eta_{gen,elec}$ is CHP electrical efficiency;
- $\eta_{gen,heat}$ is CHP heat efficiency;
- $x_{heat,t}$ is state of charge (SoC) for heat storage at time step t;
- C_{heat} is capacity of the heat storage ($C_{heat}^{min} \leq C_{heat}x_{heat,t} \leq C_{heat}^{max}$);
- $v_{heat,t}$ represents losses in the heat storage at time step t.

The process equations are divided in two parts, electricity generation and heat generation. They describe the evolution in time:

$$u_{gen,elec,t} = \eta_{gen,elec}\xi_{fuel,t} - w_{CHP,t}, \tag{21}$$

$$u_{gen,heat,t} = \eta_{gen,heat}\xi_{fuel,t} \tag{22}$$

$$\eta_{gen,total} = \eta_{gen,heat} + \eta_{gen,elec} < 1, \tag{23}$$

where $w_{CHP,t}$ is the CHP curtailed generation, at time step t, for reasons other than flexibility.

For the heat demand, the equations need to describe the capacity storage state with its losses and the demand handling as well:

$$C_{heat}x_{heat,t+1} = C_{heat}x_{heat,t} + \left(u_{gen,heat,t} - \xi_{heat,t} - v_{heat,t}\right)\Delta t, \tag{24}$$

$$v_{heat,t+1} = v_{heat\ loss}x_{heat,t}, \tag{25}$$

$$C_{heat}^{min} \le C_{heat}x_{heat,t} \le C_{heat}^{max}, \tag{26}$$

where:

- Δt is time step duration;
- $v_{heat\ loss}$ represents the self-discharge losses, proportional to the heat storage level [4].

The electric power generated can be calculated by knowing the amount of CHP's input fuel chemical power as input of the CHP. It should be noted that $x_{heat,t}$ depends on time. This will affect the bids, making them time dependent too. This point is further discussed in the aggregator's bidding strategy in Section 5.2.4.

5.2.2.2 Model for Aggregated CHPs

The aggregated flexibility model combines the power offers for all the individual CHPs, in one joint offer, at a certain time step. This can be upward flexibility or downward flexibility, which will be positive and negative, respectively, by consensus. Expressing it in a mathematical way, the aggregated flexibility at time step t is given as:

$$\Delta P_{flex,t} = \sum_{k=1}^{N_{CHP}} P_{flex,t}^{k} - P_t^{base} \tag{27}$$

where:

- $\Delta P_{flex,t}$ is aggregated flexibility at time step t;
- $P_{flex,t}^{k}$ is power of CHP k at time step t. This is a decision variable for the aggregator, and it is constrained by the model described in Section 5.2.1 (see also Section 2.4.5 in the deliverable

D1.2 [4] for more details): state of the heat storage, min/max power, possibly ramping constraints, etc.;

- P_t^{base} is aggregated baseline power at time step t;
- N_{CHP} is the total number of CHPs in the aggregated CHP offer.

5.2.3 Flexibility Cost Model

According to [4], the marginal costs of activating the flexibility of individual CHPs depend on the following terms, expressed into the flexibility cost equation:

$$c_{CHP,t}^{\text{flex}} = c_{CHP,t}^{\text{discomfort}} + c_{CHP,t}^{\text{indirect}} + c_{CHP,t}^{\text{operational}} + \Delta_{CHP,t}^{\text{revenue}}, \forall t \quad (28)$$

where:

- $c_{CHP,t}^{\text{discomfort}}$ is discomfort cost;
- $c_{CHP,t}^{\text{indirect}}$ is indirect cost;
- $c_{CHP,t}^{\text{operational}}$ are variable operational costs;
- $\Delta_{CHP,t}^{\text{revenue}}$ is revenue change from subsidies.

All above terms apart from revenue change are further explained in the sections below. The revenue change is neglected since subsidies are not expected by 2030 [4]. The cost calculations presented in this section are a further development of the calculations made in [4], in order to adapt them to the market products defined in [2].

5.2.3.1 Discomfort Cost

The discomfort cost can be roughly defined as the amount of discomfort in energy the producer is willing to experience in exchange for some economic benefit. In the case of CHP, the discomfort is primarily related to heating, and it can be expressed as the heating discomfort the consumer is willing to experience for a revenue. Thus:

$$c_{CHP,t}^{\text{discomfort}} = \lambda_{dcomf,t}\left(u_{gen,heat,t} - u_{gen,heat,t}^{base}\right)\Delta t \quad (29)$$

where:

- $\lambda_{dcomf,t}$ is the discomfort cost at time step t;
- $u_{gen,heat,t}^{base}$ is the heating power baseline, which will be obtained from the TSO, at time step t;

Further explanation can be found in [4].

5.2.3.2 Indirect Cost

The indirect cost is a result of the rebound/payback effect (i.e. modification of the baseline), under the circumstances previously described in Section 2.1 of this document. According to this section, the indirect cost is represented as:

$$c_{CHP,t}^{\text{indirect}} = \sum_{i=t_{end}^{bid}+1}^{t_{end}^{reb}} \lambda_{dev}^{i} P_{reb}^{i}\, \Delta t, \tag{30}$$

where:

- P_{reb}^{i} is the rebound power at time step *i* [kW], expressed as follows:

$$P_{reb}^{i} = \left|u_{gen,elec,i} - u_{gen,elec,i}^{base}\right|, \tag{31}$$

- $u_{gen,elec,i}^{base}$ is the electric power baseline at time step *i*, obtained from the TSO;
- $u_{gen,elec,i}$ is the new electric power baseline at time step *i*, caused by the rebound effect;
- t_{end}^{bid} is the end time step of the bid;
- t_{end}^{reb} is the end time step of the rebound period;
- λ_{dev}^{i} is the deviation price at time step *i*;
- P_{reb}^{i} is the rebound power at time step *i*;
- Δt is the time step duration.

Equation (31) gives the rebound power, which is the difference between the old and the new baseline. The absolute value in the equation ensures that it is always positive, as there is no reason for it to be negative, since it is a term used to match the energy deviation from the baseline. The profitability of the real-time trading depends on the real-time prices in next time steps, making this cost a factor depending on estimations.

From the deliverable D1.2 [4]: "it is assumed that heat storage is installed next to the CHPs, in order to allow the CHP to be flexible in the provision of electric power to the grid. This is because the heat demand $\boldsymbol{\xi_{heat}}$ is usually assumed to be inflexible and supposed to be known: $\boldsymbol{\xi_{heat}} = \xi_{heat}$ (where ξ_{heat} represents some time series of heat demand typical for the application considered). Alternatively, it could also be assumed that the heat power demand, $\boldsymbol{\xi_{heat}}$, is flexible to some extent: for instance, $\xi_{heat}^{min} \leq \boldsymbol{\xi_{heat}} \leq \xi_{heat}^{max}$."

This means that the heat demand is fixed since it is an external input to the market and previously known under a small-adjusted margin. Therefore, it is not participating in the flexibility market.

However, there are some issues about the rebound effect on the CHPs to be taken into account. The next subsections further explain the rebound effect in CHPs, and propose a general expression for the whole set of CHPs.

5.2.3.2.1 CHP configuration types

CHPs can be arranged in different configurations and installations. The heat flexibility will change with each configuration:

- **CHPs providing heat to a continuous process:** the heat load is flexible.
- **CHPs providing heat to a discontinuous process:** the heat load is less flexible than the previous.
- **CHPs aiming to produce heat:** the heat load is quite inflexible; therefore, it is difficult to provide flexibility.
- **CHPs aiming to produce steam:** there are several types:
    - **Without accumulator:** Very inflexible;
    - **With accumulator:** Flexible;

  or

    - **Without backup generators:** Less flexible (heat and electricity decoupling);
    - **With backup generators:** Inside this category, almost all of them have duct firing. Quite flexible.

5.2.3.2.2 Indirect cost types

In the flexibility market, two different cases, i.e. flexibility activations, are considered, shown in Figure 5.15. As mentioned above, a **fixed heat demand** is considered, which is linked to a **fixed heat schedule.**

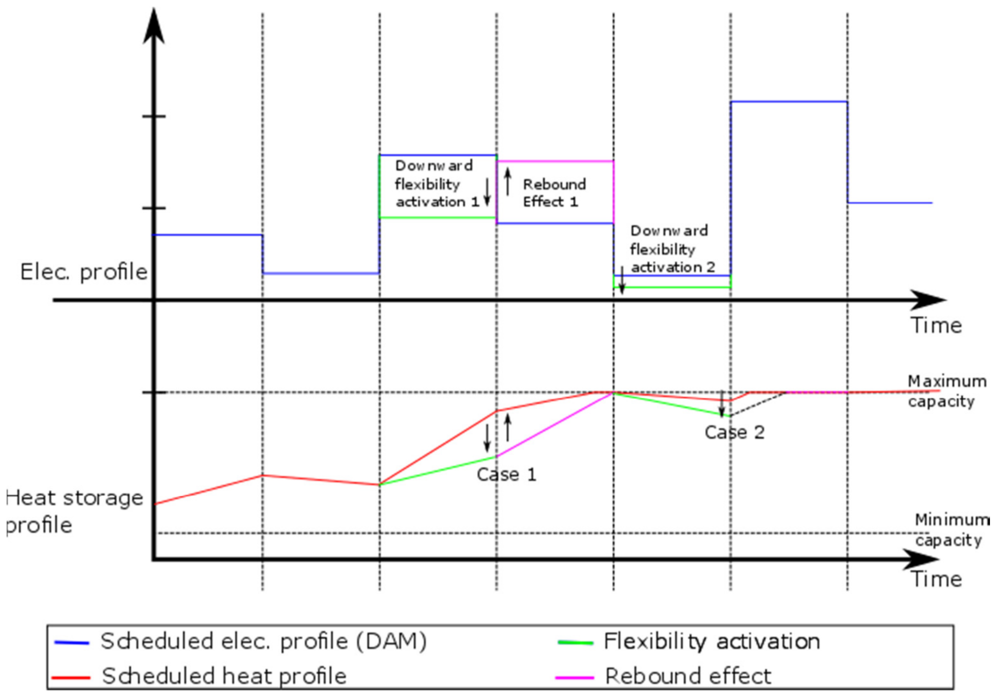


Figure 5.15 Cases of rebound effect affecting CHPs

- In the first case (shown as Downward flexibility activation 1 in Figure 5.15), the flexibility activation changes the heat profile, leading to a rebound (shown as Rebound effect 1 in Figure 5.15) to restore the original heat storage profile. Thus, the indirect cost needs to be taken into account.
- However, in the second case (shown as Downward flexibility activation 2 in Figure 5.15), the heat profile is restored by itself in the next time step due to its original profile. In this case, there is no rebound effect, leading to $c_{\mathrm{CHP},t}^{\mathrm{indirect}} = 0$.

There are other cases where the rebound effect could be neglected. For example, if the CHP has a coupling shift, which allows coupling-uncoupling the plant from the output, and there is a curtailment activation, instead of shutting down the plant and then activate it in future time steps (leading to several Variable Operation & Maintenance (VOM) costs added to the indirect cost), it could be declutched from the main shaft, along the CHP to still produce heat.

A similar case is the duct firing. The electricity generation can be lowered and use the fuel on the exhaust to heat up the boilers, increasing the heat generation.

5.2.3.2.3 General indirect cost equation

The previous cases present some concerns regarding the indirect cost, and they need to be condensed to make a real-life simulation of CHPs. To include all the possible cases into a general expression, a joint equation is proposed for the indirect cost.

Starting with the equation (31) presented before, a Boolean term is added to them with the aim of distinguish between plants with and without the rebound effect:

$$P_{reb}^{i} = \alpha_{dev} \left| u_{gen,elec,i} - u_{gen,elec,i}^{base} \right|, \tag{32}$$

$$c_{CHP,t}^{\mathrm{indirect}} = \sum_{i=t_{end}^{bid}+1}^{t_{end}^{reb}} \lambda_{dev}^{i} P_{reb}^{i} \, \Delta t, \tag{33}$$

where α_{dev} is 1 when the plant has a rebound effect and 0 when it does not have it. This factor can be another number, to express a "rebound factor," which changes depending on how flexible the plant is respecting to its heating schedule.

5.2.3.3 Variable Operational Cost

The variable operational cost is the cost difference, caused by the altered operation due to flexibility activation, in reference to the baseline operational cost [4]. It is typically associated with the fuel, CO_2 gas emissions, Operation & Maintenance (O&M), and aging costs.

$$c_{CHP,t}^{\text{operational}} = \lambda_{fuel}\left(u_{gen,elec,t} - u_{gen,elec,t}^{base}\right)\Delta t + \lambda_{CO2} r_{CO2} + c_{CHP,t}^{\text{aging}} + \lambda_{VOM,t}\left(u_{gen,elec,t} - u_{gen,elec,t}^{base}\right)\Delta t \quad (34)$$

where:

- λ_{fuel} is the fuel cost;
- $u_{gen,elec,t}^{base}$ is the power baseline of the production/consumption of the asset, which will be obtained from the TSO, at time step t;
- λ_{CO2} is the CO_2 cost;
- r_{CO2} is the CO_2 quantity generated;
- $c_{CHP,t}^{\text{aging}}$ is the aging cost;
- $\lambda_{VOM,t}$ is the Variable O&M costs.

5.2.3.3.1 Aging Cost

The aging cost can be defined by relating the installation aging after a certain number of hours and the time in when the plant is activated for flexibility. This activation implies an additional aging of the plant, so it must be considered [4].

For example, if a certain CHP has a lifetime check every 10.000 hours of functioning, the aging cost factor would be:

$$\lambda_{aging} = \frac{C_{every\ 10.000h}^{Lifetime}}{10.000h}, \quad (35)$$

$$c_{CHP,t}^{\text{aging}} = \lambda_{aging}\Delta t, \quad (36)$$

where Δt is the flexibility activation period, defined as the time period when the plant is running due to a flexibility activation. This value is usually very small for small-scale units, so in many cases it can be ignored. The value of the term $C_{every\ 10.000h}^{Lifetime}$ depends on each plant.

5.2.3.3.2 Variable Operation & Maintenance Costs

The parameter $\lambda_{VOM,t}$ includes the maintenance of the plant and the Start Up and Shut Down costs, if it is the case:

$$c_t^{Start\ Up} \geq \lambda_{SUC}\left(S_{CHP,t}^{on-off} - S_{CHP,t-1}^{on-off}\right) \quad (37)$$

$$c_t^{Shut\ Down} \geq \lambda_{SDC}\left(S_{CHP,t-1}^{on-off} - S_{CHP,t}^{on-off}\right) \quad (38)$$

where:

- λ_{SUC}, λ_{SDC} are Start Up and Shut Down costs;
- $S_{CHP,t}^{on-off}$ is ON/OFF switch status at time step t.

However, these costs may be neglected in the overall costs [4].

5.2.3.4 Total Aggregation Marginal Costs

Merging the equations presented throughout this section, the total marginal cost of a CHP plant is as follows:

$$c_{CHP,t}^{\text{flex}} = \sum_{k=1}^{N_{CHP}} \left\{ \left[\lambda_{dcomf,t}^{k} \left(u_{gen,heat,t}^{k} - u_{gen,heat,t}^{base,k} \right) + \sum_{i=t_{end}^{bid}+1}^{t_{end}^{reb}} \lambda_{dev}^{i,k} P_{reb}^{i,k} \right. \right.$$
$$\left. + \lambda_{fuel}^{k} \left(u_{gen,elec,t}^{k} - u_{gen,elec,t}^{base,k} \right) + \lambda_{VOM,t}^{k} \left(u_{gen,elec,t}^{k} - u_{gen,elec,t}^{base,k} \right) \right] \Delta t \tag{39}$$
$$\left. + c_{CHP,t}^{\text{aging,k}} + \lambda_{CO2} r_{CO2}^{k} \right\},$$

where:

- $c_{CHP,t}^{\text{flex}}$ is the aggregated cost at time step t;
- N_{CHP} is the number of CHP plants.

The total marginal cost is the value that will be set in the price of the bids offered by the aggregator to the market. Take notice that the cost is expressed in [€], as the equation has the power difference inside the terms. Also, note that this marginal cost value can depend on the sign and amount of flexibility offered.

5.2.4 Bidding Strategy

Before talking about the bidding strategy, the market type must be defined. Therefore, some assumptions have been taken for stating this strategy:

1. The market has been defined as a **market clearing** bidding. This implies that pay-as-bid will not be considered, meaning that each successful bidder will receive marginal auction price.
2. The payments are made as pure energy payments, excluding the capacity payments.

The bidding is done one time step in advance. However, a topic of discussion would be the possibility of describing the available flexibility for more than a time step in advance and the rebound effects of those biddings. Also, it can be considered that the bidding in one "market" is subject to result of the previous one.

The flexibility of each CHP is calculated individually, by making the energy-weighting average of the price components of the bids. Figure 5.16, shows the total available flexibility, picturing how much flexibility is available at a certain time step and for a certain price.

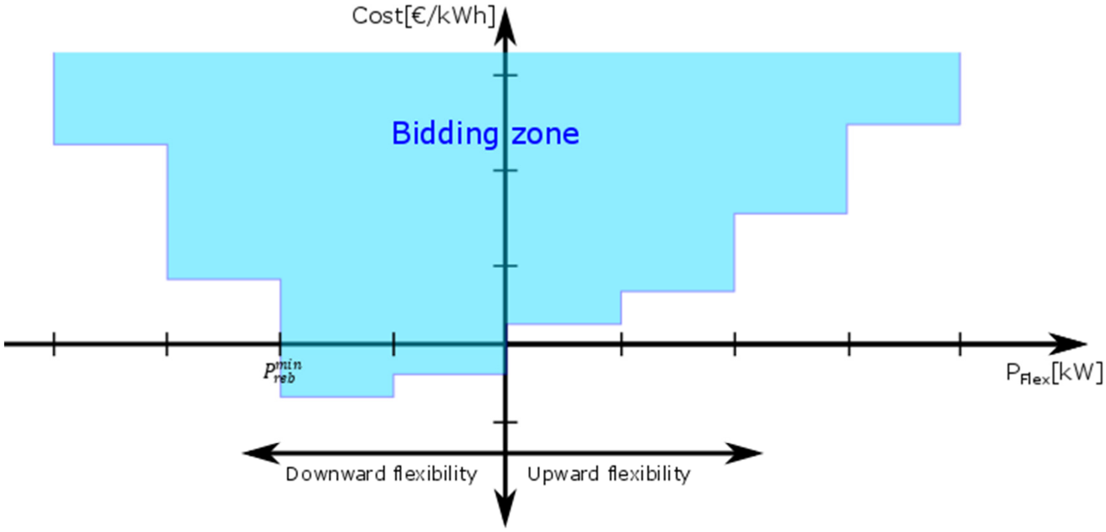


Figure 5.16 Aggregated CHPs' flexibility

The horizontal summation of bids results in Figure 5.16, a characteristic "u-shape" bid curve, which implies increased flexibility, in reference to the baseline, at rising cost. The price for the flexibility can be negative for low power at downward flexibility, due to the savings of fuel, maintenance, operation, etc. However, the downward flexibility reaches a point where the price starts to be positive, when other costs come into consideration, such as rebound costs, Start Up cost and such. This is shown in the diagram as P_{reb}^{min}, which is the downward flexibility power still offered without the rebound effect. The blue shadowed zone is the bidding zone, where the price for bidding flexibility will always give a positive benefit.

Some additional constraints also should be taken into account, such as the maximum ramp-up and rump-down of each CHP plant, Start Up and Shut Down constraints and the power constraints, defined as:

$$u_{gen,elec,t+1} - u_{gen,elec,t} \leq R^{up}\Delta t \quad (40)$$

$$u_{gen,elec,t} - u_{gen,elec,t+1} \leq R^{down}\Delta t \quad (41)$$

$$D_t^{ON} \geq MO \quad (42)$$

$$D_t^{OFF} \geq MS \tag{43}$$

where:

- R^{up}, R^{down} are ramp-up and ramp-down coefficients;
- D_t^{ON}, D_t^{OFF} are the time of operation and curtailment respectively, at time step t;
- MO, MS are the minimum operation and stop (cooling) time.

These constraints establish an operation range for the aggregated bid.

Figure 5.17 illustrates the aggregation of CHPs by the envelope approach. The minimum and maximum delivered energy of each individual CHP are added, and the ramping constraints rank the CHPs in a way that the fastest ramp plant is always the first one to be activated. However, the overall ramping constraint will be the average ramps for all the CHPs, as shown in detail in Figure 5.17. This could cause the ramping to be faster than expected, providing more energy than calculated for a particular time step. For example, when a bid is accepted, the ramping constraint, which has the average value of all the ramps, is used. In this case, only the fastest ramp is activated, which means that the activation will reach the point before expected, as the fastest ramp will be faster than the ramps' average.

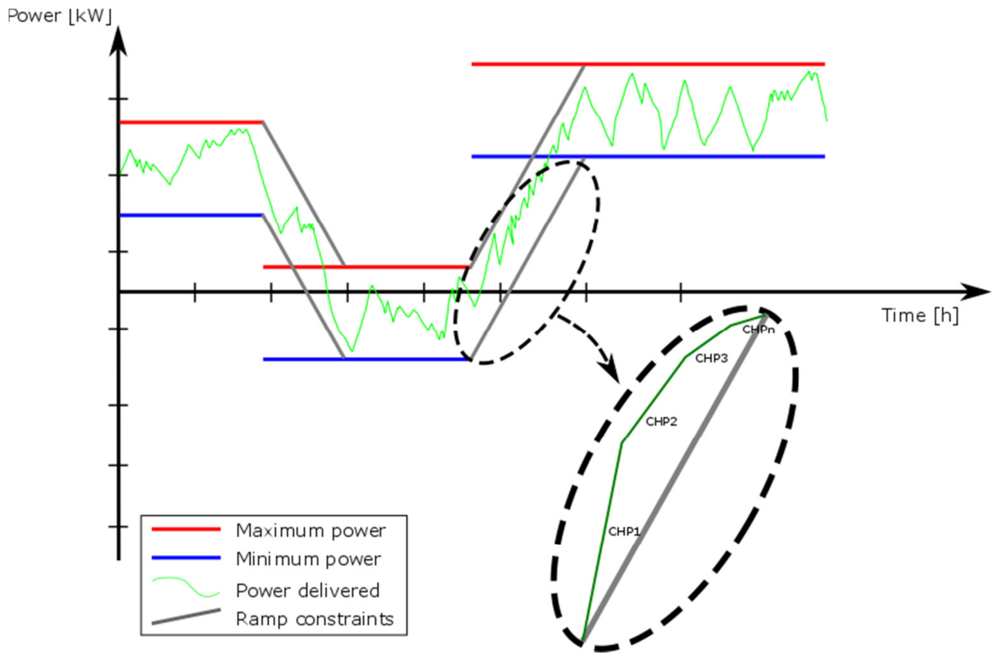


Figure 5.17 Envelope aggregation for CHPs

The maximum and minimum aggregated power are calculated through the following expressions:

$$P_t^{A,max} = \sum_{k=1}^{N_{CHP}} S_{CHP,t}^{on-off,k} P_{CHP,t}^{max,k} \tag{44}$$

$$P_t^{A,min} = \sum_{k=1}^{N_{CHP}} S_{CHP,t}^{on-off,k} P_{CHP,t}^{min,k} \qquad (45)$$

where:

- $S_{CHP,t}^{on-off,k}$ is ON/OFF switch status of the k CHP plant at time step t;
- $P_{CHP,t}^{max,k}$, $P_{CHP,t}^{min,k}$ are maximum and minimum power CHP k can deliver at time step t.

For the maximum power value, there might be a possibility of another physical constraint, depending on a distribution network.

When the heat is buffered in the plant until the consumer demands the service, the bidding strategy changes due to an increase of the topology complexity. This is considered as a "heat battery," where the energy is stored and used as convenient. The addition of the heat storage makes the CHP plant responds to changes in residual demand, optimizing the electricity prices and reducing their must-run requisite, if there is one. The inclusion of heat storage also influences the bidding strategy in the real-time market, as seen in Figure 5.18.

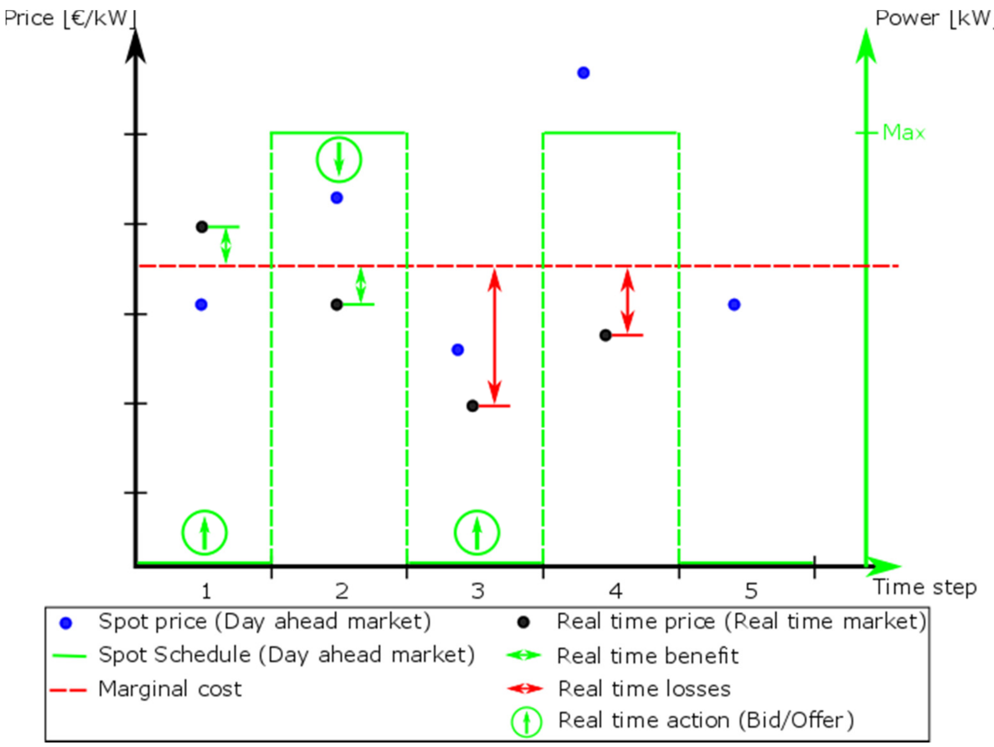


Figure 5.18 Real-time market scheme for CHPs with storage

However, this system also has the disadvantage that it may lead to unwanted heat capacity shortage. For example, in time step two, the generator is already bidding energy as scheduled but the real-time price is lower than the marginal cost, making it profitable to buy energy in that time period, with the green arrow as benefits. On the other hand, this energy purchase may have led to a capacity shortage, so

to store the promised heat, it is necessary to bid for energy during the next time step (time step 3), regardless of the real-time price. Thus, the real benefit of the actions made in time step 2 is the difference between the benefits in time step 2 and the losses in time step 3 (green arrow minus red arrow). In this example, the losses are higher than the benefits.

To avoid this worst-case scenario, a good prediction of the real-time prices is necessary, allowing smart bidding strategies to maximize the benefits. For example, time step 4 would generate fewer losses, so it would be wiser to purchase energy in this time step instead of time step 3.

For the envelope approach with heat storage, the presented model should also consider the storage capacity c_{stor} and state x_{stor} and the heat profile, in order to model the maximum and minimum power, that can be delivered, and the heat demand as well.

5.3 Thermostatically Controlled Loads

This section describes the aggregation models for the TCLs. Examples of TCLs are air conditioning systems, heat pumps, water heaters, electric heaters, etc.

The basic building blocks for the proposed aggregation models are the individual TCL physical models that have been already defined in [4]. Those models describe the electricity consumption of TCL devices using a physical representation of their thermal behavior. The thermal models describe the temperature variation with respect to time as a function of the physical characteristics of the system and its environment (heat transfer coefficients, thermal capacity, external temperature, etc.). The electricity consumption needed by the cooling/heating element is given by the amount of cooling/heating energy demand that the system requires to reach a certain temperature set point.

Flexibility is characterized by three main concepts:

1. Baseline power profile: the aggregated power profile when no control signals are sent to the TCLs.
2. Flexibility power profile: the difference between the baseline power profile and the power profile when control signals are delivered to the TCLs. The flexibility is offered by the aggregator to the market.
3. Rebound power profile: the difference between the baseline power profile and the power profile after the control signals are released. The rebound power is produced as a side effect of the flexibility activation.

The baseline power profile is calculated by aggregating the individual baseline power profiles of each TCL corresponding to their respective baseline temperature set points. These temperature baselines are needed in the flexibility models since the power flexibility of each TCL is obtained by deviating its temperature from the baseline set point. The temperature baselines would be normally considered as static values or ranges corresponding to the comfort set points set by end-users, but in cases where the aggregator also exploits the flexibility in other energy markets (day-ahead, intraday) those temperature baselines would be slightly different from the comfort temperature and depend on the time of the day. A possible approach to estimate the baseline could be based on an optimization algorithm that determines the optimal scheduling of TCLs as a function of the forecasted day-ahead market prices. The specific way in which the aggregator estimates the baseline temperatures is out of the scope of this document. In this work, it is assumed that the baseline temperature of each TCL is a known parameter.

The aggregation models presented in the section assume a direct control scheme where the control variable of TCL devices is the temperature set point. The aggregator is allowed to modify the thermostat's temperature set-point between the agreed upper and lower temperature limits. In this kind of scheme, end users always have the final decision on the set point. However, they are rewarded according to the

activated flexibility; the higher the flexibility activated, the higher also the received reward and vice-versa. Less flexible users will have high cost factors and low availabilities, while higher flexible users will have low cost factors and higher availabilities. On one hand, by increasing the temperature set point of cooling devices their power consumption is decreased and by decreasing their temperature set point, their consumption is increased. On the other hand, for heating devices, lower temperature set points decrease their consumption and higher temperature set point increase consumption. The developed algorithm uses the mentioned physical model (second-order thermal model presented in section 5.3.1.1) in order to simulate the power consumption profile of each individual TCL for the different possible temperature set-points and durations of the control (the length of the market horizon is the maximum duration, e.g. 15 min.) afterwards it aggregates the simulated individual responses in order to build the aggregated flexibility bids to be delivered to the market.

It has to be taken into account that the activation of a flexibility profile has an associated power rebound profile. For instance, if TCLs are requested to reduce their consumption during two consecutive time periods, this will cause an increase in consumption during the next two time periods in order to recover the baseline conditions. It is not straightforward to delay the rebound effect since the comfort temperature is not recovered until the rebound effect takes place. In case the rebound effect is delayed, the internal temperature is maintained at a value different from the comfort temperature. The considered approach is based on trying to recover the base case temperature as soon as possible by having the rebound effect just after the end of the control period. This way, the power consumption comes back to the optimal profile derived from the participation in the day-ahead and intraday markets. Once the base case temperature has been recovered, the TCL is ready for control again. It has to be noted that in some situations, mainly in large scale applications of DR, it could be necessary to apply also control actions to the rebound in order to limit its peak value. However, the study of the methods to optimally schedule the rebound is out of the scope of this work.

This section presents two approaches for modeling TCL flexibility and its activation costs:

1. Envelope approach: It is based on the bottom-up approach where the flexibility and costs of individual TCLs are firstly modeled in order to create individual TCL bids. These bids are then aggregated in order to create bids that represent the complete population of TCLs, i.e. the bids that are finally delivered by the aggregator to the market.
2. Justified approximation approach[19]: The behavior of the entire set of TCLs is represented by a single, or a limited number of aggregated device models, which follow the same structure as

[19] This approach is valid for both the direct and indirect control. In case of the direct control it has the advantage of being very scalable. If there are hundreds or thousands of aggregated devices, it enables the reduction of the computation time. And for the indirect control it is the most logical way of doing things.

the individual TCL model whose parameters have been adapted to represent the entire population of TCLs (e.g. average values).

The envelope approach is described in section 5.3.2 and the justified approximation approach in section 5.3.3. The justified approximation approach is suitable in case of homogeneous set of TCLs, where all the thermal characteristics and status of the TCLs are the same or very similar. As the heterogeneity of the TCL population increases, the number of clusters of TCLs having similar model parameters increases. In the extreme case where the number of clusters equals the number of TCLs, it becomes the envelope (bottom-up) approach.

In addition to the flexibility and costs models, two bidding strategies are presented:

1. Single time step bids: This bidding strategy consists of creating bids for the next market time period only (e.g. 5 minutes). STEP non-curtailable Q bids are generated.
2. Multiple time step bids: The multi-period bidding strategy creates flexibility profile bids. These flexibility profiles span for more than one market time step (e.g. 1 hour that includes 12 time steps of 5 minutes). STEP non-curtailable Qt bids are generated.

The combination of modelling approaches and bidding strategies produce a set of four different alternatives for the aggregation modelling (see Figure 5.19).

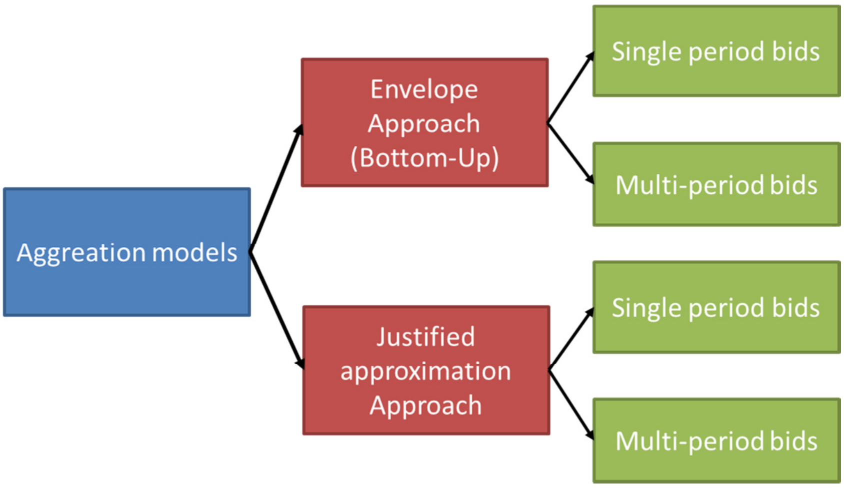


Figure 5.19 Aggregation model alternatives

5.3.1 Individual TCL Flexibility and Cost Models

In [4] two continuous thermal models, a thermal model for a water heater and a thermal model for a heat pump, are described. The thermal model for the water heater is defined as a first-order thermal model while the heat pump thermal model is a more complex, second-order thermal model.

Based on these particular models, this section provides a generic thermal model for TCLs based on the continuous second-order thermal model. This model is valid for all kinds of TCL devices (heat pumps, air-

conditioning systems, water heaters, fridges, etc.). The developed TCL model is the basis for the aggregation approaches described in Section 5.3.2 and 5.3.3.

5.3.1.1 Individual TCL Thermal Model

Following an ETP (Equivalent Thermal Parameter) approach [38]-[40], the generic thermal model can be represented by its electric equivalent, as shown in Figure 5.20, where resistances represent thermal transfer coefficients, capacitances represent thermal capacity of thermal masses and heating/cooling energy injections are represented by current sources. The thermal system is enveloped, and it contains internal mass, which needs to be cooled or heated. In the case of a household/building heating, ventilation and air conditioning (HVAC) system, the internal thermal mass represents the air inside the building, while for a water heater; the internal mass is the water inside the tank. The envelope of the thermal system represents the insulating envelope from the exterior containing the internal mass. In the case of a HVAC system, the envelope consists of the walls, ceiling, roof, etc., while for the water heater, the envelope is the tank, which stores the water. For HVAC systems, solar heat gains are considered in Q_{env} representing the heat gains in the system's envelope.

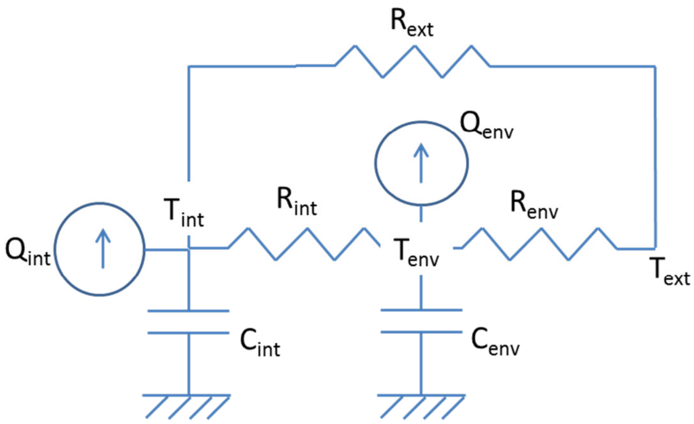


Figure 5.20 Electrical equivalent of a second-order ETP model

The parameters needed for the ETP model are the following:

- C_{int} is thermal capacity of the internal mass;
- C_{env} is thermal capacity of the envelope mass;
- R_{int} is heat transfer coefficient between the internal mass and the envelope;
- R_{env} is heat transfer coefficient between the envelope mass and the exterior;
- R_{ext} is heat transfer coefficient between the internal mass and the exterior;
- Q_{int} is internal heat/cool gains;
- Q_{env} is envelope heat/cool gains;
- T_{int} is internal temperature;

- T_{env} is envelope temperature;
- T_{ext} is external temperature.

The thermal equations are given as two coupled differential equations describing the evolution of temperature (internal and envelope) with the time:

$$C_{int}\frac{dT_{int}}{dt} = Q_{int} + \frac{1}{R_{int}}(T_{env} - T_{int}) + \frac{1}{R_{ext}}(T_{ext} - T_{int}) \tag{46}$$

$$C_{env}\frac{dT_{env}}{dt} = Q_{env} + \frac{1}{R_{int}}(T_{int} - T_{env}) + \frac{1}{R_{env}}(T_{ext} - T_{env}) \tag{47}$$

The internal heating/cooling gains Q_{int} represent the sum of the energy gains produced by the elements inside the system's envelope. In the case of HVAC systems, the internal gains include the heat produced by the people in the building, the heat produced by the loads (lights, TVs, refrigerator, etc.) and the heat/cold produced by the HVAC system itself. In case of water heaters, the internal heat gains represent the heat losses produced by the hot water extracted from the water heater when it is being used. It is however important to differentiate between both the heat gains coming from the heating or cooling system and the rest of gains. The heating or cooling energy production by the heating or cooling system is the one that is responsible for the electric energy consumption of the TCL.

$$Q_{int} = Q_{gains} + \eta P_{elec} \tag{48}$$

where:

- Q_{gains} are the internal thermal gains;
- η is the electric to thermal power conversion factor;
- P_{elec} is the power supplied by the electric heating/cooling device.

The electric to thermal conversion factor η is a characteristic of the heating/cooling device.

The differential equations described above can be discretized following Euler's method, resulting in two linear equations that describe the variation of internal and envelope temperatures between time step *i* and time step *i+1*:

$$C_{int}(T_{int}^{i+1} - T_{int}^{i}) = \left[Q_{gains}^{i} + \eta P_{elec}^{i} + \frac{1}{R_{int}}(T_{env}^{i} - T_{int}^{i}) + \frac{1}{R_{ext}}(T_{ext}^{i} - T_{int}^{i})\right]\Delta t \tag{49}$$

$$C_{env}(T_{env}^{i+1} - T_{env}^{i}) = \left[Q_{env}^{i} + \frac{1}{R_{int}}(T_{int}^{i} - T_{env}^{i}) + \frac{1}{R_{env}}(T_{ext}^{i} - T_{env}^{i})\right]\Delta t \tag{50}$$

Knowing the initial state of the internal and envelope temperatures, the electric power needed to obtain a certain internal temperature can be calculated. The desired internal temperature is in fact the temperature set point of the TCL (T_{sp}). So, by setting $T_{int}^{i+1} = T_{sp}$, the amount of electric power consumed by the device can be calculated (P_{elec}^{i}). In case in which the needed power is higher than the actual maximum power of the TCL (P_{elec}^{max}), the power consumption will be P_{elec}^{max} and the desired temperature will not be reached. Therefore, the final internal temperature can be calculated with the thermal model equations by setting $P_{elec}^{i} = P_{elec}^{max}$ and having T_{int}^{i+1} as unknown variable.

Note that even if [4] recommends the use of the second-order thermal model, there is always the possibility to use first-order thermal models if during the implementation phase it is not possible to obtain the required data. In such case, the thermal model would be simplified by using one single equation as follows:

$$C_{int}\left(T_{int}^{i+1} - T_{int}^{i}\right) = \left[Q_{gains}^{i} + \eta P_{elec}^{i} + \frac{1}{R_{ext}}\left(T_{ext}^{i} - T_{int}^{i}\right)\right]\Delta t \tag{51}$$

5.3.1.2 Individual TCL Flexibility Cost Model

According to [4], the marginal costs of activating the flexibility of individual TCLs consist of the following terms:

1. operational cost,
2. indirect cost, and
3. discomfort cost.

The cost calculations presented in this section go beyond the descriptions made in [4], taking into account aggregation considerations and adapting them to the market products defined in [2].

5.3.1.2.1 Operational Cost

At the aggregation level, the deviations during the flexibility activation are not considered since they have been generated on a request of the market, and therefore they do not incur in a cost (or revenue).

Therefore, at an aggregation level the operational costs do not represent any real cost and can be considered to be zero:

$$c_{op} = 0 \tag{52}$$

where:

- c_{op} is the operational cost.

5.3.1.2.2 Indirect Cost

The indirect costs correspond to the costs derived from deviating from the baseline power profile during the energy rebound period. This power deviation has not been requested by the market but it represents a side effect caused by the activation of flexibility. There are two options how to consider this energy rebound cost:

1. Bids with inter-bid logical constraints: Assumes that the flexibility market allows incorporating "Accept-All-Time-Steps-Or-None" constraint (see [2]). In this case, the indirect cost will be zero for the aggregator because the power profile offered within the bid includes both the flexibility period and the rebound period.
2. Bids without inter-bid logical constraints: Consider that the rebound energy produces a deviation with respect to the baseline profile that is penalized according to the network operator's deviation penalization procedures.

On the one hand, the second option assumes that an undesired deviation is produced. In addition to this, it is difficult to predict the deviation price that will be used for the penalization and that is not known beforehand. On the other hand, the first option gives complete information to the market so that an optimal solution can be calculated taking into account the energy rebound effect. In any case, both options are considered in this section.

5.3.1.2.2.1 Bids with Inter-Bid Logical Constraint

In case of delivering bids with "Accept-All-Time-Steps-Or-None" constraints, the indirect cost caused by the energy rebound will be zero:

$$c_{ind}^{i} = 0, \tag{53}$$

where c_{ind}^{i} is indirect cost at time step *i*.

The use of the "Accept-All-Time-Steps-Or-None" constraint is only valid for the case where the rebound effect takes place within the market time horizon.

For a given activated flexibility quantity, the individual TCL rebound power profile is calculated by setting the temperature set point after the end of the activation period to the comfort temperature set point (or the one considered in the baseline). The power profile required to restore this set point is calculated using the thermal equations (individual TCL model in Section 5.3.1.1) taking the temperature at the end of the activation period as the starting point.

5.3.1.2.2.2 Bids without Inter-Bid Logical Constraint

In case of not using integral constraints, the indirect costs will depend on the deviation price (forecasted deviation price more precisely):

$$c_{ind}^{i} = \sum_{i=t_{end}^{bid}+1}^{t_{end}^{reb}} \lambda_{dev}^{i} E_{reb}^{i} = \sum_{i=t_{end}^{bid}+1}^{t_{end}^{reb}} \lambda_{dev}^{i} P_{reb}^{i}\, \Delta t \quad (54)$$

where:

- c_{ind}^{i} is the indirect cost;
- t_{end}^{bid} is the end time step of the bid (end of the flexibility activation);
- t_{end}^{reb} is the time step of the end of the rebound effect;
- λ_{dev}^{i} is the deviation price at time step *i*;
- E_{reb}^{i} is the energy rebound at time step *i*;
- P_{reb}^{i} is the power rebound at time step *i;*
- Δt is the duration of the considered time step.

Note that P_{reb}^{i} is calculated by setting $T_{sp}^{i} = T_{bc}$ from time step $i = (t_{end}^{bid} + 1)$ until time step t_{end}^{reb} , that is, until the base case temperature set point has been restored for the TCL.

Note also that a constant baseline temperature set point is assumed. In the most general case, the baseline temperature set point would vary with time especially if the aggregator is participating in other energy markets (day-ahead or intraday).

5.3.1.2.3 Discomfort Cost

An easily interpretable and intuitive way to represent discomfort costs is to define them as: the amount of discomfort in terms of temperature deviation from the base case that a consumer is willing to experience in exchange of some economic benefit. In this work the discomfort cost for an individual TCL at time step *i* is represented as a linear function [27]:

$$c_{cft}^{i} = \delta \left| T_{int}^{i} - T_{bc} \right| \quad (55)$$

where:

- c_{cft}^{i} is discomfort cost at time step *i*;
- δ is the parameter measuring the economic benefit to be obtained for a unit of temperature deviation;
- T_{int}^{i} is the internal temperature set point at time step *i*;
- T_{bc} is the baseline temperature.

For an internal temperature set point, which is the same as the baseline temperature, the discomfort cost is zero and, as the difference is increased, the cost increases linearly.

In a more general way, it could be considered that the relation of the discomfort cost with the temperature deviation from the base case does not follow a linear function but an exponential one. One alternative to equation (55) would be to define the following quadratic function:

$$c_{cft}^{i} = \delta \left(T_{int}^{i} - T_{bc}\right)^{2} \tag{56}$$

The δ parameter is a subjective parameter that depends on each user's sensitivity to temperature discomfort. In a practical system, this parameter should be agreed between the user and the aggregator and probably the user would be allowed to configure it in the control system.

A practical way to estimate the δ parameter is to assume that at the maximum discomfort level, the end user will be willing to receive the money that it should have paid for maintaining the temperature comfort level. This can be expressed as:

$$\delta = \frac{\lambda_{elec}^{i}}{\left|T_{disc} - T_{bc}\right|} \tag{57}$$

where:

- δ is the parameter measuring the economic benefit to be obtained for a unit of temperature deviation;
- λ_{elec}^{i} is the price of electricity at time step *i*;
- T_{disc} is the maximum discomfort temperature for the end user;
- T_{bc} is the baseline temperature.

If a quadratic function is used for the discomfort cost, the equation for the calculation of δ would be the following one:

$$\delta = \frac{\mathrm{\lambda}_{\mathrm{elec}}^{\mathrm{i}}}{\left(\mathrm{T}_{\mathrm{disc}} - \mathrm{T}_{\mathrm{bc}}\right)^{2}} \quad (58).$$

5.3.2 Envelope Approach (Bottom-up)

The envelope approach or bottom-up approach consists of summing up the power calculated for the individual TCL models [41]-[44]. In this approach, it is assumed that the aggregator knows all the parameters of each individual TCL device and its real-time status (availability, current temperature set point etc.). The aggregator is therefore able to estimate the flexibility and associated costs of each individual TCL using the thermal models in the previous Section 5.3.1.

The temperature set point of the thermostat controlling the TCL is the control variable used to modify its power consumption. The upward flexibility (consumption reduction) of a TCL is obtained by increasing the temperature set point for cooling systems or decreasing it for heating systems. In a similar way, downward flexibility (consumption increase) corresponds to the case in which the temperature set point is decreased for cooling systems and increased for heating systems. The allowed maximum and minimum temperature variations are restricted by some maximum and minimum temperature limits beyond which the discomfort created to the end user is unacceptable. These temperature set point limits determine the flexibility range and are defined by the user of the load and agreed by contract with the aggregator.

5.3.2.1 Single-period Bid Creation Model

The simplest market scenario considered in the SmartNet project is the one in which bids are delivered for a single time period. This scenario is closer to currently existing balancing markets without inter-bid logical constraints [1].

5.3.2.1.1 Aggregation Model

The flexibility from TCLs is obtained by changing their temperature set points. Following this rule, single step bids are created in the following way:

1. For each TCL in the population to be aggregated, calculate the flexibility and its cost when different temperature set points are applied. The temperature set points might be changed in a discrete way within the minimum and the maximum temperature limits. This calculation will result in a set of individual step non-curtailable bids where each step (flexibility vs. cost) corresponds to one temperature set point.
2. The horizontal summation of all the individual bids produces an aggregated step non-curtailable bid. The horizontal summation consists of ordering the bid steps by price and summing their energy volumes starting from the cheapest step and ending at the most expensive step.

The following notation will be used in the formulation:

- N_{TCL} is number of TCL devices in the aggregation set;
- $P_{flex}^{i,s,k}$ is the flexible power for time step *i*, temperature set point *s* and TCL *k*;
- $P_{bc}^{i,k}$ is the baseline power for time step *i*, and TCL *k*;
- $P_{ctl}^{i,s,k}$ is the controlled power for time step *i*, temperature set point *s* and TCL *k*;
- P_{max}^{k} is the maximum power for TCL *k*;
- $P_{dem}^{i,s,k}$ is the power needed to reach the desired temperature set point *s* during time step *i* for TCL *k*;

- $P_{ctl}^{i,s,k}$ is the consumed power (controllable power) for temperature set point *s* time step *i* and TCL *k*;
- C_{int}^{k} is thermal capacity of the internal mass for TCL *k*;
- R_{int}^{k} is heat transfer coefficient between the internal mass and the envelope for TCL *k*;
- R_{ext}^{k} is heat transfer coefficient between the internal mass and the exterior for TCL *k*;
- $Q_{gains}^{i,k}$ is internal heat/cool gains for time step *i* and TCL *k*;
- $T_{sp}^{i,s,k}$ is temperature set point for time step *i* set point level *s* and TCL *k*;
- T_{spmax}^{k} is maximum allowed temperature set point for TCL *k*;
- T_{spmin}^{k} is minimum allowed temperature set point for TCL *k*;
- T_{spset}^{k} is set of temperature set points for TCL *k*;
- ΔT_{sp}^{k} is relative temperature set point change for TCL *k*;
- N_{sp} is number of set points to be considered;
- $T_{int}^{i,k}$ is internal temperature for time step *i* and TCL *k*;
- $T_{env}^{i,k}$ is envelope temperature for time step *i* and TCL *k*;
- $T_{ext}^{i,k}$ is external temperature for time step *i* and TCL *k*;
- C_{env}^{k} is thermal capacity of the envelope mass for TCL *k* ;
- R_{env}^{k} is heat transfer coefficient between the envelope mass and the exterior for TCL *k*;
- $Q_{env}^{i,k}$ is envelope heat/cool gains for time step *i* and TCL *k*;
- $T_{env}^{i,k}$ is envelope temperature for time step *i* and TCL *k*;
- δ^{k} is price sensitivity parameter for TCL *k* ;
- λ_{dev}^{j} is deviation price for time step *j* ;
- $c_{ind}^{i,s,k}$ is the indirect cost, that is the cost of the rebound energy for time step *i*, temperature set point *s* and TCL *k*;
- $c_{flex}^{i,s,k}$ is cost during the flexibility activation at step *i*, temperature set point *s* and TCL *k*;
- $P_{reb}^{j,k}$ is rebound power for time step *j* and TCL *k*;
- t_{end}^{reb} is the end time step of the rebound effect;
- $E_{int}^{i,s,k}$ is integral energy for bid at time step *i*, TCL *k* and set point *s* ;
- $E_{flex}^{i,s,k}$ is flexibility energy for bid at time step *i*, TCL *k* and set point *s*;
- $E_{reb}^{i,s,k}$ is rebound energy for bid at time step *i*, TCL *k* and set point *s*.

Each bid step for a single TCL at time step *i* is calculated with the following equations:

$$P_{flex}^{i,s,k} = P_{bc}^{i,k} - P_{ctl}^{i,s,k} \tag{59}$$

$$P_{ctl}^{i,s,k} = min\left(P_{max}^{k}, P_{dem}^{i,s,k}\right) \tag{60}$$

Note that the real power consumption $P_{ctl}^{i,s,k}$ is limited by the maximum power of the TCL P_{max}^{k}. So, if the power demand $P_{dem}^{i,s,k}$ is higher than the maximum power, the consumption will be the maximum power and the desired temperature set point will not be reached (see equation (67) below).

The power needed to reach the control temperature set point $T_{sp}^{i,s,k}$ is calculated by isolating the power variable in the thermal equation (49):

$$P_{dem}^{i,s,k} = \frac{1}{\eta}\left[\frac{1}{\Delta t} C_{int}^{k}\left(T_{sp}^{i,s,k} - T_{int}^{i,k}\right) - Q_{gains}^{i,k} - \frac{1}{R_{int}^{k}}\left(T_{env}^{i,k} - T_{int}^{i,k}\right) - \frac{1}{R_{ext}^{k}}\left(T_{ext}^{i,k} - T_{int}^{i,k}\right)\right] \tag{61}$$

The set of N_{sp} number of set points for TCL k is defined as:

$$T_{spset}^{k} = \left\{T_{spmin}^{k} + \Delta T_{sp}^{k}, T_{spmin}^{k} + 2\Delta T_{sp}^{k}, T_{spmin}^{k} + 3\Delta T_{sp}^{k}, \dots, T_{spmin}^{k} + N_{sp}\Delta T_{sp}^{k}\right\} \tag{62}$$

$$\Delta T_{sp}^{k} = \frac{T_{spmax}^{k} - T_{spmin}^{k}}{N_{sp}} \tag{63}$$

$$T_{sp}^{i,s,k} \in T_{spset}^{k} \tag{64}$$

Note that the temperature set point $T_{sp}^{i,s,k}$ is restricted by the minimum T_{spmin}^{k} and maximum T_{spmax}^{k} allowed temperature set point limits that depend on the user's settings.

Additionally, the envelope temperature $T_{env}^{i,k}$ needed in equation (61) is calculated by isolating the corresponding temperature variable from equation (47):

$$T_{env}^{i,k} = \frac{\Delta t}{C_{env}^{k}}\left[Q_{env}^{i-1} + \frac{1}{R_{int}^{k}}\left(T_{int}^{i-1,k} - T_{env}^{i,k}\right) + \frac{1}{R_{env}^{k}}\left(T_{ext}^{i-1,k} - T_{env}^{i-1,k}\right)\right] + T_{env}^{i-1,k} \tag{65}$$

With this method, both the upward and downward flexibility can be calculated. For cooling systems, when the chosen temperature set point is higher than the base case temperature, upward flexibility is calculated, and when the temperature set point is lower than the base case temperature, downward flexibility is calculated. In a similar way, for cooling systems, when the chosen temperature set point is lower than the base case temperature, upward flexibility is calculated, and when the temperature set point is higher than the base case temperature, downward flexibility is calculated.

As previously described in Section 5.3.1.2.2, two possibilities can be considered when defining the price for a bid:

1. Bids without inter-bid logical constraints
2. Bids with inter-bid logical constraints

For single time step bids, temporal constraints that relate multiple time steps are not applicable and therefore only the first option (no temporal constraints) is considered. Without temporal constraints the indirect costs need to be considered. The total cost for a certain flexibility step at temperature set point $T_{sp}^{i,s,k}$ is calculated as:

$$c^{i,s,k} = c_{flex}^{i,s,k} + c_{ind}^{i,s,k} = \delta^k \left| T_{int}^{i+1,k} - T_{bc}^{i,k} \right| + \sum_{j=\mathrm{i}+1}^{t_{end}^{reb}} \lambda_{dev}^{j} P_{reb}^{j,k} \Delta t \tag{66}$$

The first term contains the costs related to the loss of comfort (deviation in temperature), while the second term considers the rebound effect (the indirect cost). In the rebound effect part, $j = i + 1$ represents the time step just after the flexibility activation ends, and t_{end}^{reb} represents the time step when the base case temperature is recovered.

The internal temperature at the end of the time step to be used in the cost equation $T_{int}^{i+1,k}$ is calculated by isolating the internal temperature variable in the thermal equation (49):

$$T_{int}^{i+1,k} = \frac{\Delta t}{C_{in}^{k}} \left[P_{ctl}^{i,k} \eta + Q_{gain}^{i,k} + \frac{1}{R_{int}^{k}} \left(T_{env}^{i,k} - T_{int}^{i,k} \right) + \frac{1}{R_{ext}^{k}} \left(T_{ext}^{i,k} - T_{int}^{i,k} \right) \right] + T_{int}^{i,k} \tag{67}$$

The rebound energy $P_{reb}^{j,k}$ at time step j is calculated with equations (59), (60) and (61) by setting the temperature set point $T_{sp}^{j,s,k}$ to the base case temperature set point value ($T_{sp}^{j,s,k} = T_{bc}^{j,k}$) and calculating the difference respect to the base case power. The rebound effect is the sum of the rebound power for every time step j starting at the time step after the end of the activation and until the base case temperature is reached, that is, until $P_{reb}^{j,k} = 0$.

Note that each power vs. price step in the aggregated bid needs a "non-curtailable" constraint. In addition, it has to be noted that the bids are submitted to the market in energy units (MWh and €/MWh for power flexibility and price respectively) and with the previous formulation they have been calculated in absolute units of power (MW) and price (€). Consequently, unit conversion is required before sending them to the market by applying the next formulation:

$$E_{flex}^{i,s,k} = P_{flex}^{i,s,k} * \Delta t \tag{68}$$

$$C^{i,s,k} = \frac{c^{i,s,k}}{E_{flex}^{i,s,k}} \tag{69}$$

5.3.2.1.1.1 Algorithm Flow Chart

A flow chart representing the calculation phases in the single-step bid creation algorithm is shown in Figure 5.21.

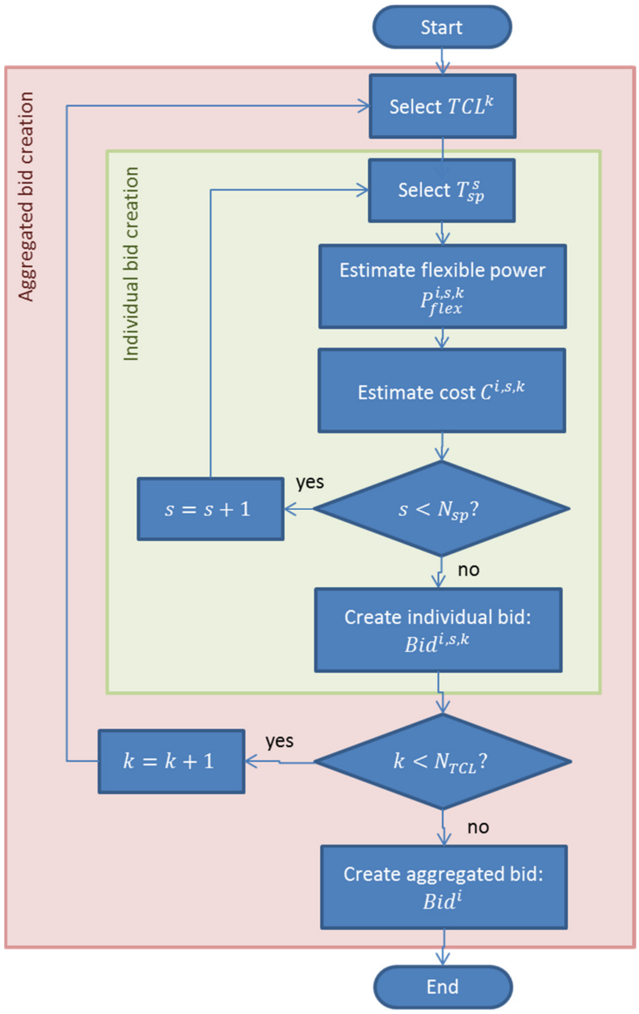


Figure 5.21 Single-step bid creation flow chart using the envelope modeling approach

The flow chart shows the process for creating single-step aggregated bids: For each TCL in the aggregation set, the flexibility and costs (individual bid) for each control temperature set point are calculated (N_s is the number of temperature set points to simulate). The aggregated bid is created by the horizontal summation of individual TCL bids (N_{TCL} is the number of aggregated TCL devices).

5.3.2.1.1.2 Example of the Bid Creation Process

The described bid creation process has been implemented as an example using a first order thermal model and for upward flexibility. These simplifications have been done since the objective of the example is to facilitate the understanding of the approach and not the implementation of a full simulation model. It is considered that the aggregator has three different TCLs in its portfolio. The characteristics of each of them are shown in Table 5.3.

Table 5.3 Model parameters for the single-step bid creation process example

Model parameters	TCL^1	TCL^2	TCL^3
Thermal mass capacity C_{int} [J/C]	2.80E+06	2.75E+07	2.75E+07
Heat transfer coefficient R_{int} [C/W]	0.0053	0.0053	0.0053
Heat gains Q_{int} [W]	1100	600	1100
External temperature T_{ext} [C]	35	35	40
Base case temperature T_{bc} [C]	23	23	23
Efficiency η [$W_{thermal}/W_{electric}$]	3.20	3.20	3.20
Maximum power P_{max} [W]	3200	3200	3200
Initial temperature T^0_{int} [C]	23	23	23
Price sensitivity factor δ [€/C]	0.001	0.001	0.001

As it can be seen in the model parameters table, TCLs differ on the values on the thermal parameters of the envelope as well as on the external temperature. This leads to obtaining different flexibility profiles for each of them. These are represented in Figure 5.22. For each TCL two flexibility quantities are offered, each corresponding to a different temperature set-point (23.5 ºC and 24 ºC). In this figure, the aggregated bid is also shown. It is composed of all individual flexibilities ordered by incremental price (merit-order).

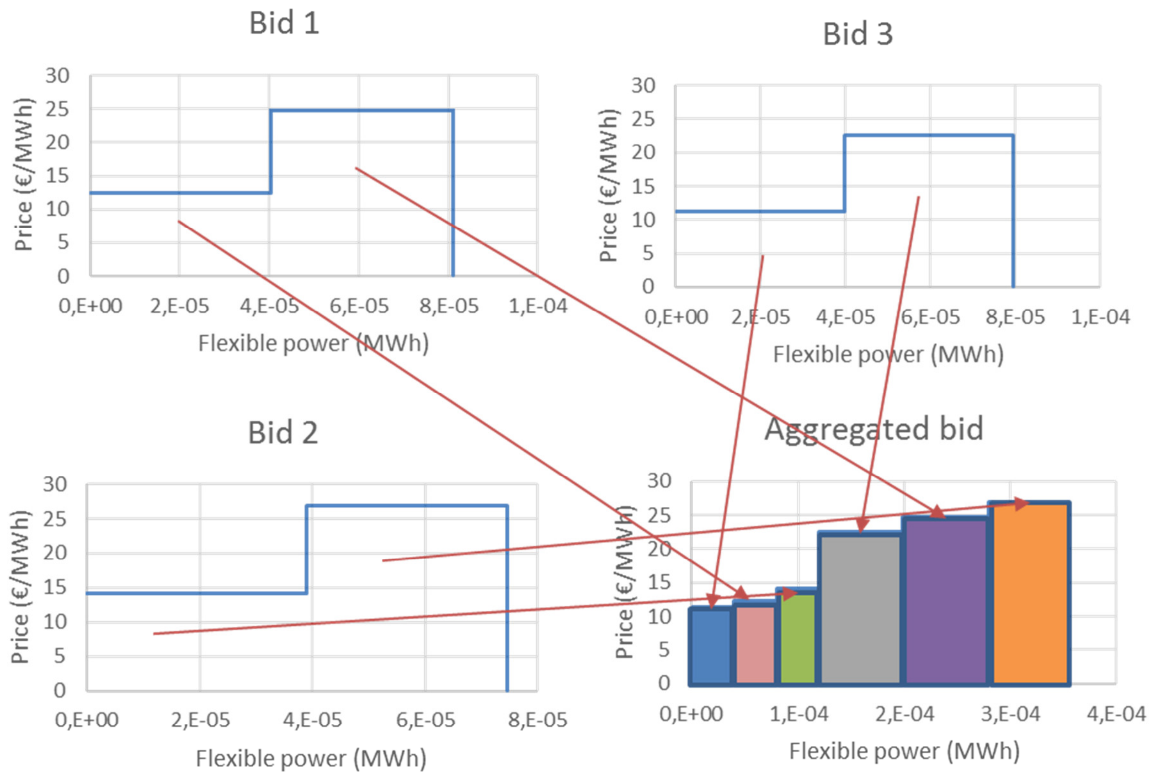


Figure 5.22 Example of the aggregation of three single-step bids

Note that the bids are submitted with a "non-curtailable" constraint, such that each device's flexibility (corresponding to a step in the bid) is accepted completely or not accepted at all.

5.3.2.1.1.3 Simplified Algorithm for Short Duration Time Steps

Note that the described bid creation algorithm can be simplified assuming that the time step duration is low comparing to the internal temperature variation time constant. This is for sure the case of 5 minutes duration time steps where the thermal inertia produces very low variations in the internal temperature of the TCL. In these cases, only three temperature set point levels are enough for estimating the flexibility instead of iterating through several temperature set points as indicated in the more general case (see Section 5.3.2.1.1):

1. $T_{sp}^{i,s,k} = T_{spmax}^{k}$: By setting the temperature set point to the maximum value, the maximum upward flexibility for cooling systems and downward flexibility value for heating systems is obtained. Any set point temperature between $T_{int}^{i,k}$ and T_{spmax}^{k} will produce the same flexibility.

2. $T_{sp}^{i,s,k} = T_{spmin}^{k}$: In a similar way, setting the temperature set point to the minimum value, the maximum downward flexibility for cooling systems and upward flexibility value for heating systems is obtained. Any set point temperature between T_{spmin}^{k} and $T_{int}^{i,k}$ will produce the same flexibility.
3. $T_{sp}^{i,s,k} = T_{int}^{i,k}$: Setting the temperature set point equal to the internal temperature yields the third possible flexibility value if $T_{int}^{i,k} \neq T_{bc}^{i,k}$.

The reason for having only these three flexibility levels is that any change in the temperature set point (first and second cases) produces a thermal transient that lasts for a long time comparing to the market time step of 5 minutes. In these cases, the TCL either consumes the minimum power (zero) leaving the internal temperature to freely reach the new set point (when $T_{sp}^{i,s,k} = T_{spmax}^{k}$ for cooling systems and $T_{sp}^{i,s,k} = T_{spmin}^{k}$ for heating systems) or consumes the maximum power (when $T_{sp}^{i,s,k} = T_{spmin}^{k}$ for cooling systems and $T_{sp}^{i,s,k} = T_{spmax}^{k}$ for heating systems) in order to force the internal temperature to the set point. The third case represents a steady state case in which the TCL needs to maintain the temperature at the same level and compensate for the heat gains and losses.

$$\text{For cooling systems: } \begin{cases} for\ T_{sp}^{i,s,k} = T_{spmax}^{k} \Rightarrow P_{flex}^{i,k} = P_{bc}^{i,k} \\ for\ T_{sp}^{i,s,k} = T_{spmin}^{k} \Rightarrow P_{flex}^{i,k} = P_{bc}^{i,k} - P_{max}^{k} \\ for\ T_{sp}^{i,s,k} = T_{int}^{i,k} \Rightarrow P_{flex}^{i,k} = P_{bc}^{i,k} - P_{flex}^{i,s,k} \end{cases} \tag{70}$$

$$\text{For heating systems: } \begin{cases} for\ T_{sp}^{i,s,k} = T_{spmax}^{k} \Rightarrow P_{flex}^{i,k} = P_{bc}^{i,k} - P_{max}^{k} \\ for\ T_{sp}^{i,s,k} = T_{spmin}^{k} \Rightarrow P_{flex}^{i,k} = P_{bc}^{i,k} \\ for\ T_{sp}^{i,s,k} = T_{int}^{i,k} \Rightarrow P_{flex}^{i,k} = P_{bc}^{i,k} - P_{flex}^{i,s,k} \end{cases} \tag{71}$$

In this way, each individual bid (upward or downward) has maximum two steps; one corresponding to the situation in which the temperature set point is equal to the internal temperature set point (corresponding to the steady state power consumption) and the other when the temperature set point is different to the internal temperature (corresponding to the transient state) when the maximum flexibility can be obtained.

5.3.2.1.1.4 Reactive power bid

For TCLs, reactive power (ϴ) is directly determined by the active power (P) according to ϴ = P * tg(φ), φ being the power factor angle which is a known parameter. According to this, the reactive power value for the bids is calculated as follows:

$$\Theta_{flex}^{i,s,k} = P_{flex}^{i,s,k} * tg(\varphi), \tag{72}$$

$P_{flex}^{i,s,k}$ being the active power flexibility for time step *i*, temperature set point *s* and TCL *k*.

The reactive power bid is defined with the two half plane constraints, for each Qt bid, being the slope of both constraints the power factor angle. The two constraints will have opposite directions in order to represent the fixed factor angle [2].

5.3.2.2 Multi-period Bid Creation Model

The multi-step creation model is defined for market schemes that allow submitting multi-step bids with inter-temporal bid constraints. This is the more general case of the market algorithms being developed in [2].

The key point that needs to be taken into account is that the flexibility that a TCL can provide at each time step depends on the past states of the TCL (see equations (49) and (50)). Additionally, those past states depend on the baseline and the flexibility activated for balancing purposes in the past. A way to address this issue is to offer entire flexibility profiles that span more than one time step. This can be done by including "Accept-All-Time-Steps-Or-None" constraints as defined in [2]. In practice, this means that the aggregator offers entire flexibility profiles, rather than single-step independent flexibility values. These flexibility profiles include both, the flexibility period and the rebound period. Finally, since there are potentially infinite power profiles that could be offered, the aggregator needs to choose the profile creation criteria that best matches market needs and, therefore, offers more opportunities for its bids to be accepted. This is a similar approach as the one described for the aggregation of atomic loads in Section 5.1, where the possible profile alternatives are combined in order to match market needs and therefore obtain the maximum benefit.

To this end, the following criteria forms the basis of the aggregators' bidding strategy:

1. Aggregated bids should support the market, both when rapid variations in the balancing needs are required and when more stable and sustained imbalances are needed to be solved. This will provide the aggregator with more opportunities for its bids to be accepted in different balancing conditions.
2. The bids should contain different power quantities, so that the market clearing algorithm has more choices when selecting bids and, therefore, the aggregator has more possibilities for some of its bids to be accepted.

In order to address both requirements, an algorithm based on iterating over different time durations (addressing point 1) and temperature set points (addressing point 2) is proposed and described in the following sections.

5.3.2.2.1 Aggregation Model

The algorithm for the creation of multi-step bids is based on estimating the flexibility profiles of individual TCLs for a predefined set of temperature set points and predefined set of time durations. The

predefined set of set points is based on defining temperature set points relative to the particular limits of the TCL.

The following notation will be used in the formulation:

- N_{TCL} is number of TCL devices in the aggregation set;
- T_{spset}^{k} is set of temperature set points for TCL k;
- $T_{sp}^{s,k}$ is temperature set point s for TCL k;
- T_{spmin}^{k} is minimum allowed temperature set point for TCL k;
- T_{spmax}^{k} is maximum allowed temperature set point for TCL k;
- ΔT_{sp}^{k} is relative temperature set point change for TCL k;
- N_{sp} is number of set points to be considered;
- D_{prof} is set of power duration profiles;
- D_{prof}^{n} is duration of power profile n;
- N_{ts}^{tot} is total number of market time steps;
- N_{ts} is number of profile time periods to be considered;
- $Prof_{flex}^{n,s,k}$ is flexibility profile for duration n, set point s and TCL k;
- $\lambda_{prof}^{n,s,k}$ is price for the flexibility profile for duration n, set point s and TCL k;
- $c^{i,s,k}$ is cost for time step i set point s and TCL k;
- $c_{flex}^{i,s,k}$ is flexibility activation costs for time step i, temperature set point s and TCL k;
- λ_{dev}^{j} is deviation penalty price at time step j;
- $P_{reb}^{j,k}$ is rebound power at time step j and TCL k;
- Δt is market time period;
- $E_{int}^{n,s,k}$ is integral energy constraint for profile duration n, set point s and TCL k;
- $E_{flex}^{n,s,k}$ is flexible energy for profile duration n, set point s and TCL k;
- $E_{reb}^{n,s,k}$ is rebound energy for profile duration n, set point s and TCL k.

The set of N_{sp} number of set points for TCL k is defined in the same way as in Section 5.3.2.1.1 (see equations (62) and (63).

In a similar way, the time duration in time steps of the flexibility profiles to calculate can be defined as a set of N_{ts} number of time periods:

$$D_{prof} = \{\Delta D_{prof}, 2\Delta D_{prof}, 3\Delta D_{prof}, \dots, N_{ts}^{tot}\} \tag{73}$$

$$\Delta D_{prof} = \frac{N_{ts}^{tot}}{N_{ts}} \tag{74}$$

The total number of bids is the multiplication of the number of set points by the number of profile time periods ($N_{sp} \times N_{ts}$). As an example, a total market time period of one hour with five minutes time steps ($N_{ts}^{tot} = 12$) is assumed. If $N_{ts} = 6$ and $N_{sp} = 6$, the total number of bids will be 36. The result of the bid creation process will be a set of six bids (one per temperature set point) for a flexibility profile of 10 minutes, another six bids for a flexibility profile of 20 minutes, and so on until the last six bids for the total duration of the market (60 minutes).

The equations for calculating the flexibility and costs are almost the same as the ones defined in Section 5.3.2.1.1 (equations (59)-(65) for flexibility and equations (66)-(69) for prices). The only difference in the calculation process is that instead of calculating flexibility and costs for a single time step, the number of time steps to be considered depends on the length of the flexibility profile being calculated.

The power profile for TCL *k*, profile duration *n* and set point *s* is composed by the set of flexibilities for each time period in the profile:

$$Prof_{flex}^{n,s,k} = \left\{P_{flex}^{1,s,k}, P_{flex}^{2,s,k}, P_{flex}^{3,s,k}, \dots, P_{flex}^{D_{prof}^{n},s,k}\right\} \tag{75}$$

Regarding the consideration of flexibility costs, the same possibilities as the ones described in Section 5.3.2.1.1 can be taken into account:

1. Bids without inter-bid logical constraints
2. Bids with inter-bid logical constraints

For multi-step bids, only the second option is considered. In that case the "Accept-All-Time-Steps-Or-None" constraint is defined. The time-period covered by this constraint includes both, the flexibility period and the rebound period. Note also that the rebound effect should be within the market time period; this fact restricts the maximum length of the flexibility profiles. The costs will cover the part related to the temperature deviation:

$$\lambda_{prof}^{n,s,k} = \sum_{i=0}^{i+D_{prof}^{n}} c_{flex}^{i,s,k} \tag{76}$$

The generated profiles (bids) should incorporate the following constraints:

- "Accept-All-Time-Steps-Or-None:" In order to ensure the complete acceptance of each flexibility (and rebound) profile.
- Exclusive choice: This way, in case of acceptance, only one of the profiles will be accepted.

In addition, it has to be noted, as mentioned for single period bids, that the bids are submitted to the market in energy units (MWh and €/MWh for power flexibility and price respectively) and with the

previous formulation they are calculated in absolute values of power (MW) and price (€). Consequently, unit conversion is required before sending them to the market (see equations (68) and (69)).

5.3.2.2.1.1 Algorithm Flow Chart

The algorithm formulated in Section 5.3.2.2.1 is described as a flow chart in Figure 5.23 below.

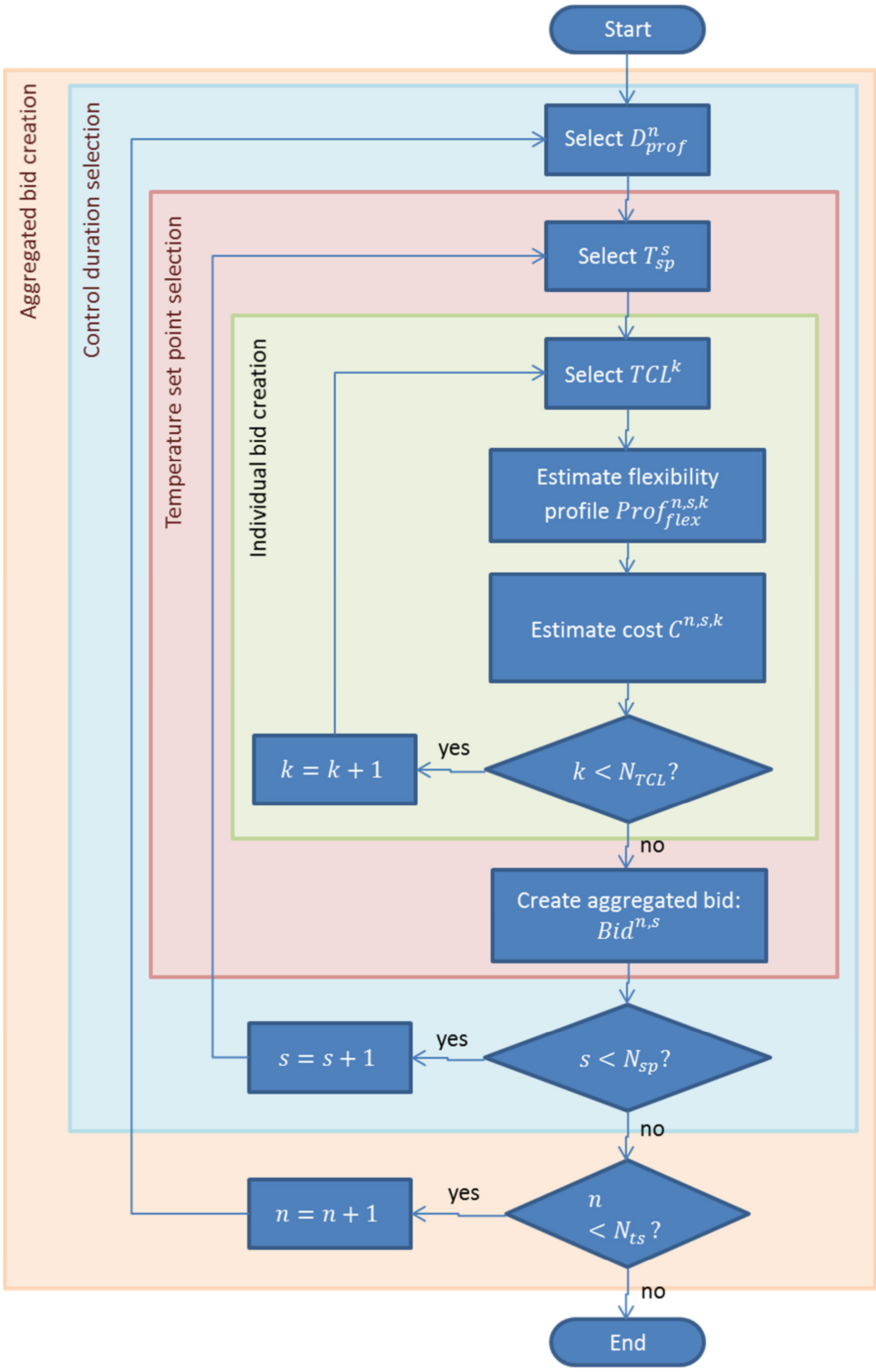


Figure 5.23 Flow chart of the multi-step bid creation process

There are three main loops in the proposed bid creation procedure:

1. Bid duration loop: The set of profile durations is defined by equations (73) and (74). At each iteration of this loop, a set of bids of aggregated power profiles is created. Each bid is composed by a power profile where flexibility quantities are offered for each market time step in the bid period. Each power profile is associated to a price and to an "Accept-All-Time-Steps-Or-None" constraint in order to ensure its complete acceptance in the time axis. The loop starts with one market time step and terminates when all the market horizon duration is covered.
2. Temperature set point loop: A set of temperature deviation set point levels (same for all TCLs) are defined following equations (62) and (63). For each temperature set point, the aggregated power profile and the corresponding price are obtained. The aggregated power profile and cost are calculated as the sum of the individual TCL calculations made in the inner individual TCL loop.
3. Individual TCL loop: For each TCL *k* in the aggregated set, temperature set point *s* (taken from the temperature set point set) and profile duration *n* (taken form the duration set), an individual power profile is calculated, together with the associated costs. Each power profile contains the flexibility power values for each time step considered in the profile duration period.. The flexibility and costs are calculated using equations (76).

The result of the bid creation process will be a set of $N_{sp} x N_{ts}$ aggregated power profiles, where the values in each profile are accompanied by an "Accept-All-Time-Steps-Or-None" constraint. Each power profile will have a price associated with it. Since the profiles are mutually exclusive, they will be associated to an "*exclusive choice constraint.*" The result of the market clearing process should be either one of the offered power profiles (to be paid at the bid price or higher) or none.

5.3.2.2.1.2 Example of the Bid Creation Process

As a simple example of the multi-period bid creation process, the following points are assumed:

- An aggregation of three TCLs ($TCL = [TCL^1, TCL^2, TCL^3]$).
- A set of three temperature set points as possible control actions (same for the three TCLs) ($T_{sp}(C) = \{T_{sp}^1, T_{sp}^2, T_{sp}^3\} = \{23.5, 24, 24.5\}$).
- Three durations for the flexibility profiles ($N_{ts} = 3$) with a market time horizon duration of one hour with a time step length of 5 minutes ($N_{ts}^{tot} = \frac{60}{5} = 12$). Each profile has three time step duration ($\Delta D_{prof} = \frac{12}{4} = 3$). This gives a profile duration set of $D_{prof} = \{D_{prof}^1, D_{prof}^2, D_{prof}^3\} = \{3, 6, 9\}$ that translated to minutes is $\{15, 30, 45\}$.
- This setup will yield a set of nine ($N_{sp} \times N_{ts} = 3 \times 3 = 9$) aggregated flexibility profile bids. The duration of each profile depends on the duration of the considered profile (duration of the

control action) and the corresponding rebound period caused by the application of that control.

The results of the simulations are based on a first order thermal model (see Section 5.3.1). These simplifications have been adopted since the only purpose of this example is to illustrate the multi-step bid creation process for its easier understanding.

The thermal characteristics of the three TCLs systems are shown in Table 5.4.

Table 5.4 Model parameters for the multi-period bid creation process example

Model parameters	TCL^1	TCL^2	TCL^3
Thermal mass capacity C_{int} [J/C]	2.75E+06	2.75E+06	1,38E+06
Heat transfer coefficient R_{int} [W/C]	0.0053	0.0106	0.0053
Heat gains Q_{int} [W]	1100	1100	1100
External temperature T_{ext} [C]	35	40	35
Base case temperature T_{bc} [C]	23	23	23
Efficiency η [$W_{thermal}/W_{electric}$]	3.20	3.20	3.20
Maximum power P_{max} [W]	3200	3200	3200
Initial temperature T^0_{int} [C]	23	23	23
Price sensitivity factor δ [€/C]	0.001	0.001	0.001

As it can be seen in the model parameters table, TCLs differ on the values of the thermal parameters of the envelope as well as on the external temperature. This leads to obtaining different flexibility profiles for each of them. The results of the individual bids are represented in Figure 5.24, Figure 5.25 and Figure 5.26 with the corresponding flexibility profiles (power vs. time) and prices. For each TCL three bid sets are calculated (one per considered profile duration). Each bid set includes three bids corresponding to the different temperature set-points considered (24 ºC, 24.5 ºC and 25 ºC). Note that for the shorter time durations (three time steps), the flexibility profile provided by different set points for TCL^2 is the same, this is why there are only two flexibility profile for the profile set of three time periods. Figure 5.27 shows the aggregated set of bids which is composed by summing up the individual profiles corresponding to the same temperature set point and time duration.

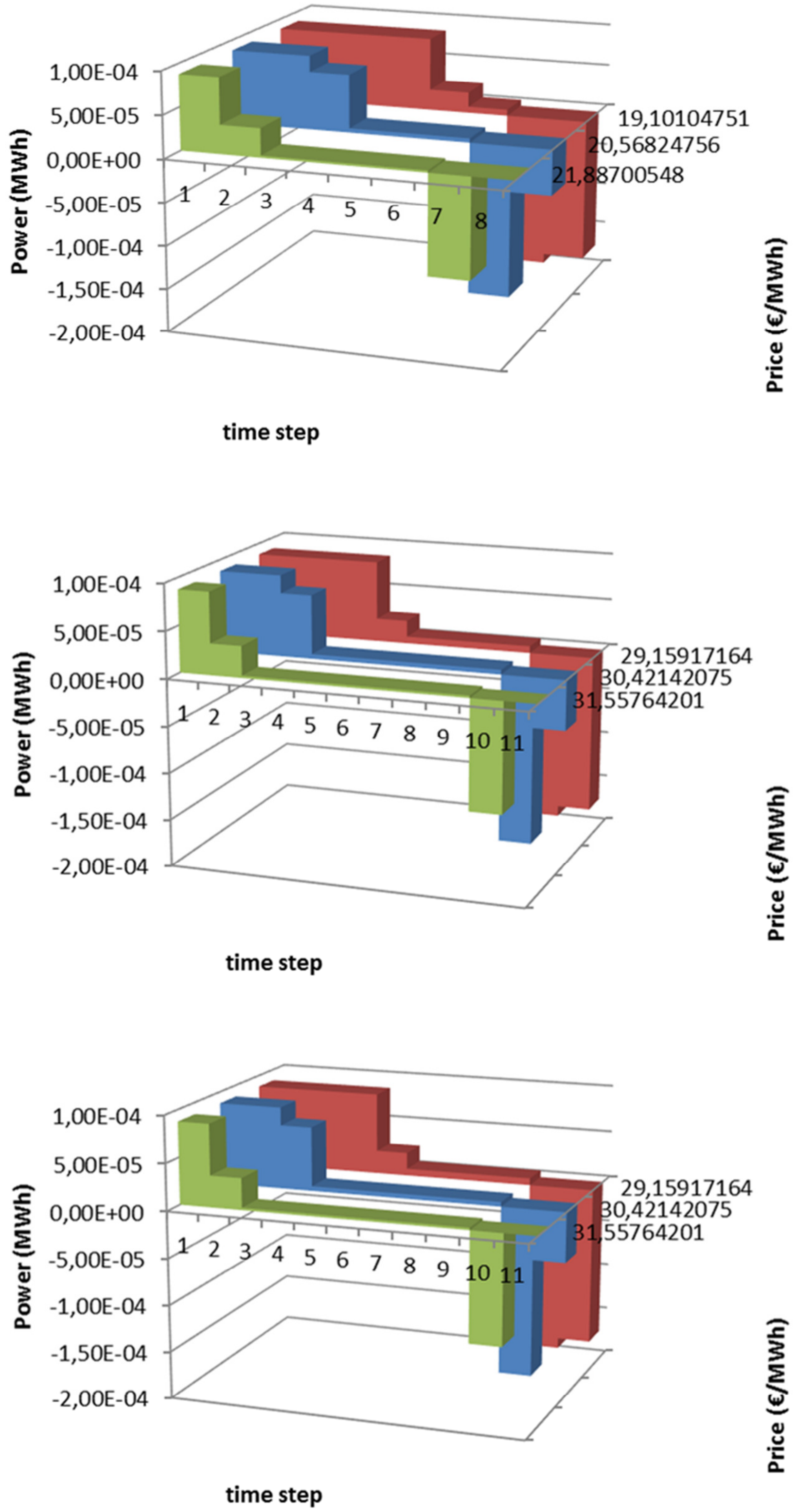


Figure 5.24 Flexibility bids for $\boldsymbol{TCL^1}$ for different time durations and temperature set points

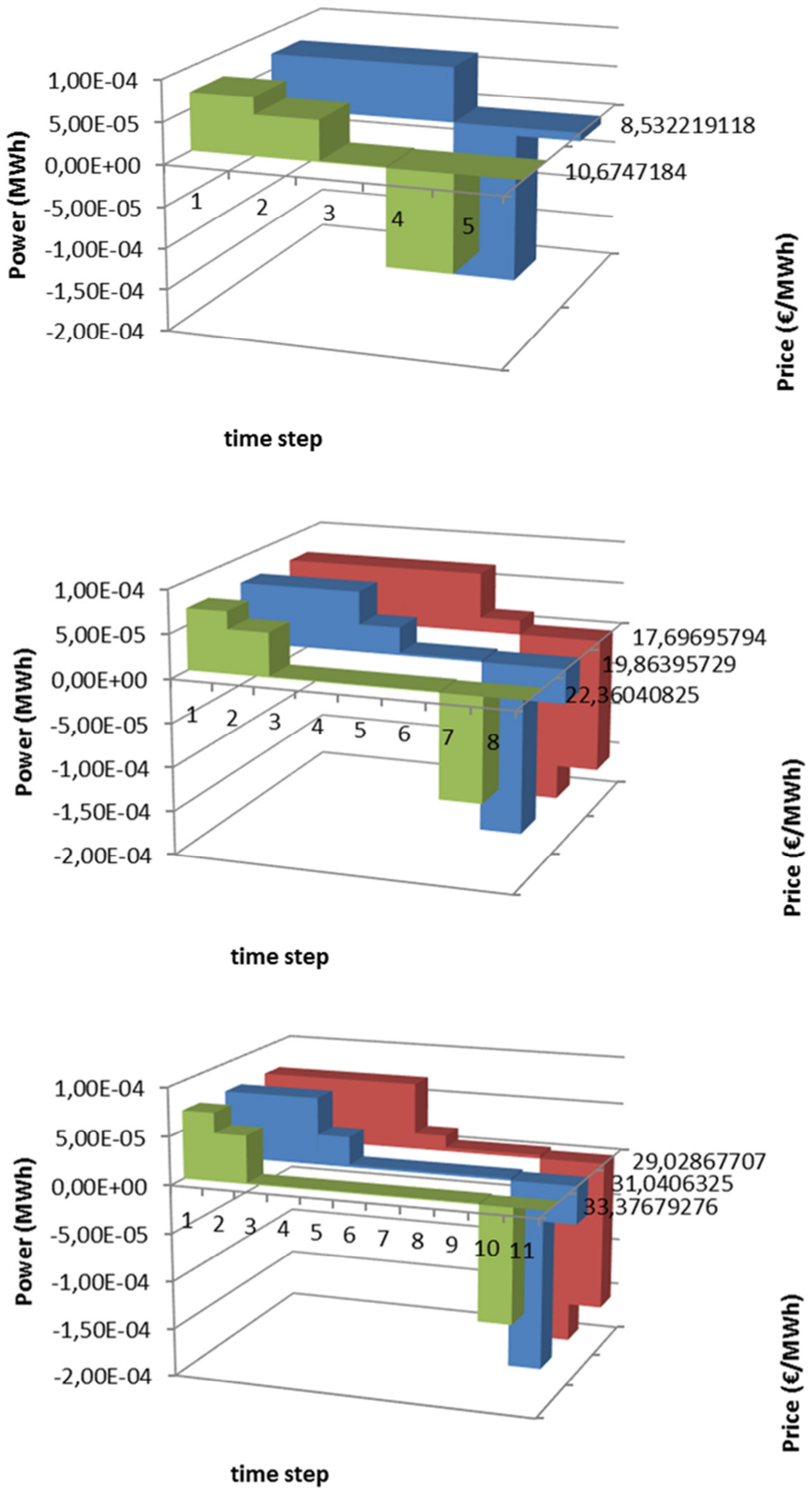
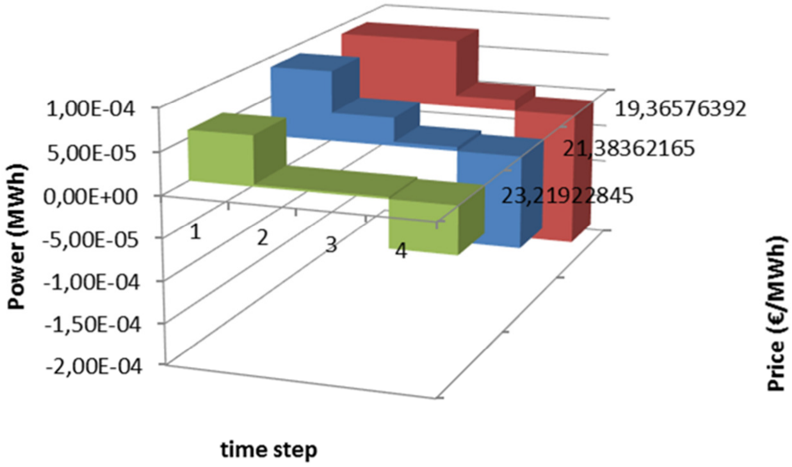
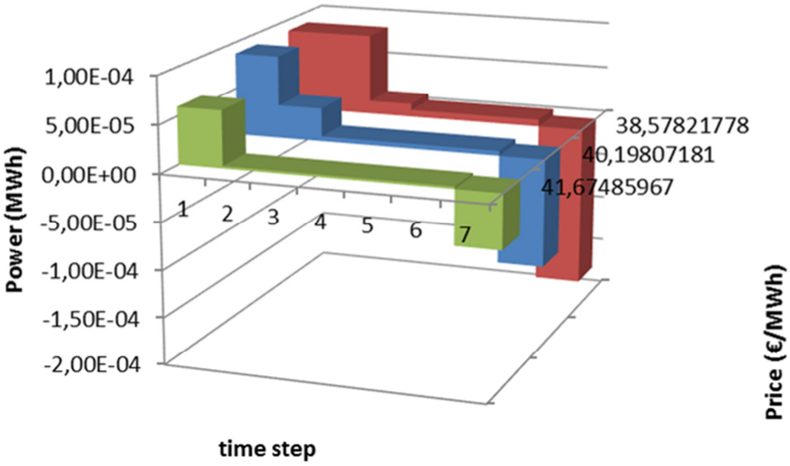


Figure 5.25 Flexibility bids for $\boldsymbol{TCL^2}$ for different time durations and temperature set points





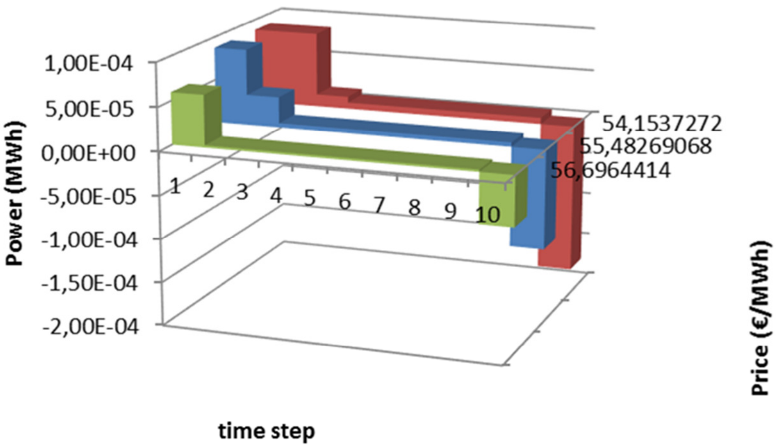


Figure 5.26 Flexibility bids for $\boldsymbol{TCL^3}$ for different time durations and temperature set points

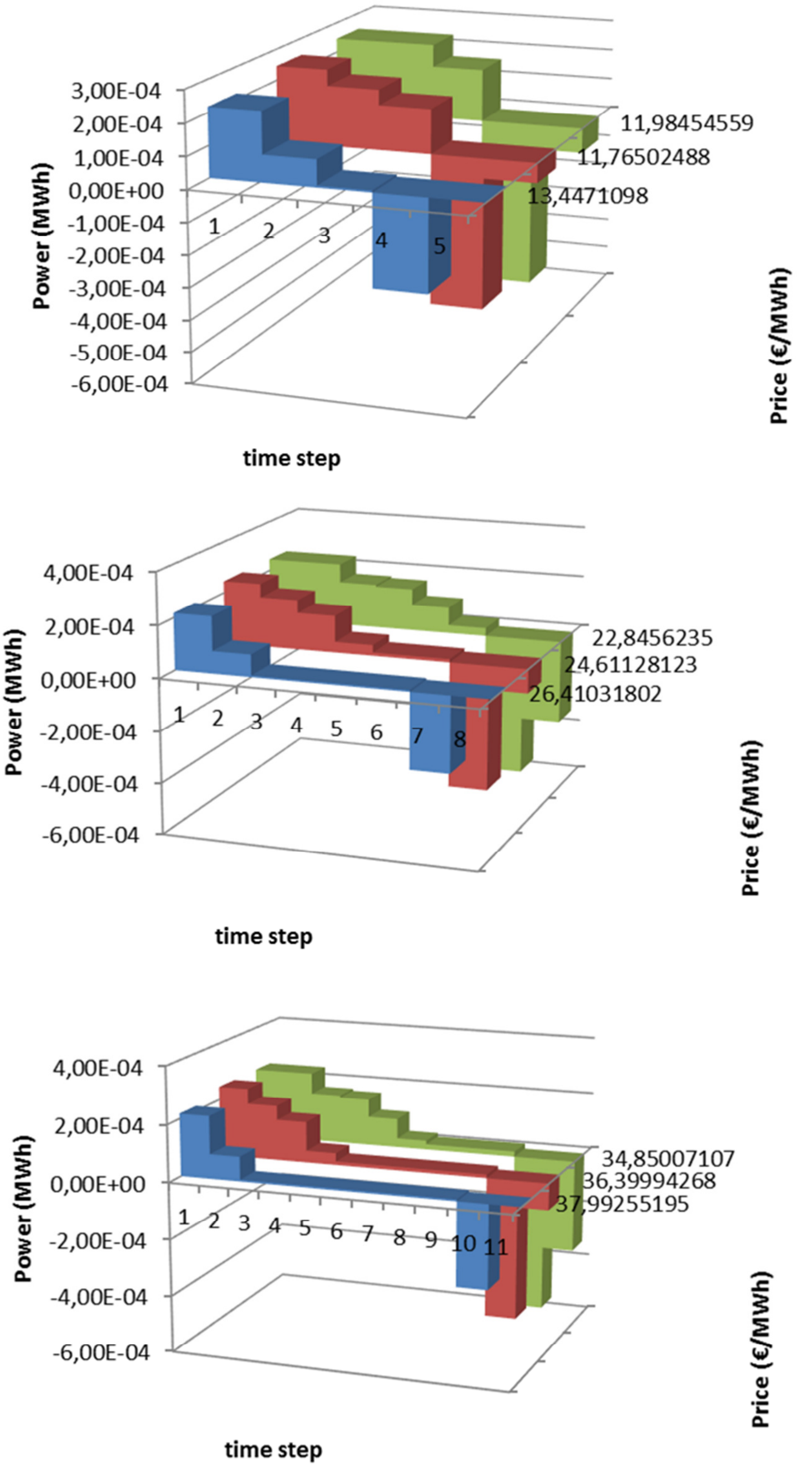


Figure 5.27 Flexibility power profiles for the aggregated set of TCLs

Note that for short market time steps there is no power granularity in the aggregated power profile bids. A way to obtain a higher level of granularity would be to divide the set of individual TCLs into different groups and make the aggregation process by TCL group.

5.3.2.2.1.3 Reactive power bid

The reactive power constraint for multi-step bids is calculated in a similar way as explained for single-period bids in section 5.3.2.1.1.4.

5.3.3 Justified Approximation Modelling Approach

The justified approximation modelling approach uses a single or a limited number of TCL models, in order to represent the entire population of aggregated devices. It does so by using averaged parameters in the model.

The case assumed here is the case of a homogenous set of TCLs where all the thermal characteristics and status of the TCLs are the same or very similar. In this case, it is clear that the aggregated power and costs of the set of TCLs can be represented by a single TCL multiplied by the number of TCLs in the set.

$$P_{flex}^{i,s} = N_{TCL} \times P_{flex}^{i,s,k} \tag{77}$$

$$\lambda^{i,s} = N_{TCL} \times \lambda^{i,s,k} \tag{78}$$

where:

- $P_{flex}^{i,s}$ is the aggregated flexible power at time step *i* and for set point *s*;
- N_{TCL} is the number of TCLs;
- $P_{flex}^{i,s,k}$ is the flexible power for the average TCL at time step *i* and for set point *s*;
- $\lambda^{i,s}$ is the aggregated price at time step *i* and for set point *s*;
- $\lambda^{i,s,k}$ is the price for one of the TCLs at time step *i* and for set point *s*.

The complete formulation for $P_{flex}^{i,s,k}$ and $\lambda^{i,s,k}$ is the one given in the equations described in Section 5.3.2.1.1 and Section 5.3.2.2.1.

As the heterogeneity of the TCL population increases, the flexibility model would be built by using average parameters in the flexibility and cost equations. In case of heterogeneous TCLs, the justified approximation approach introduces an error. A way to reduce this error is to make clusters of TCLs having similar model parameters, in order to have a number of homogeneous TCL sets. In case of using clustering techniques, the number of TCL models will be the same as the number of clusters. A possible algorithm for TCL clustering is the *k*-means algorithm that allows creating K number of clusters for the population of N_{TCL} devices [29]-[31].

$$P_{flex}^{i,s} = \sum_{c=1}^{c=N_{clus}} N_{TCL}^{c} \times P_{flex}^{i,s,c} \tag{79}$$

$$\lambda^{i,s} = \sum_{c=1}^{c=N_{clus}} N_{TCL}^{c}\,\lambda^{i,s,c} \tag{80}$$

where:

- N_{clus} is number of clusters;
- N_{TCL}^{c} is number of TCLs in cluster c;
- $P_{flex}^{i,s,c}$ is flexibility for time step i, set point s and cluster c;
- $\lambda^{i,s,c}$ is price for time step i, set point s and cluster c.

As the number of clusters increases, the justified approximation approach becomes closer to the bottom-up approach. Moreover, in the extreme case where the number of clusters equals the number of TCLs, it becomes the bottom-up approach. In general, when using the justified approximation approach, it is recommendable to define more than one cluster even when the TCL set is very homogeneous. The reason for this is to enable enough degrees of freedom for the scheduling, i.e. for allowing separately controlled groups. Finally, it has to be noted that sometimes the justified approximation approach might give more accurate forecasts than the bottom up approach. In case inaccurate values of the model parameters and states were available, the introduced errors might not cancel each other when summing up the individual responses.

For the creation of the bids, the exact same equations and processes as described in Sections 5.3.2.1 and 5.3.2.2 can be applied but replacing the individual model parameters with the parameters of the TCL clusters.

5.4 Electric Energy Storage Units

This section describes the technical characteristics as well as mathematical formulation of the aggregation model for stationary and mobile EES, as well as small PHES. PHES units store electric energy in the form of water in an upper reservoir. The power is generated by discharging water from the upper reservoir during the peak periods (high price hours). In contrast, electric power is used from the grid to pump water from the lower reservoir back to the upper reservoir during off-peak hours (low price periods). EVs, both plug-in hybrid and all-battery vehicles, are facing rapid expansion. According to [45], the worldwide EV penetration is assumed to increase up to 20 million units by 2020. Moreover, they are utilized only 4-5% of the time for transportation, making them potentially available the remaining 95-96% of the time for an alternative use [46]. It is estimated that at least 90% of the personal vehicles are parked even during the peak traffic hours [47].

Therefore, there is a significant potential in using the stationary and EV batteries to assist the electric power grid [48], although their investment cost remains relatively high [4]. However, a single storage unit cannot enter to electricity market to trade their energy for the following two reasons: 1) the available trading power of individual storage is below the required threshold to participate in electricity markets [49], and 2) the participation of the individual storage will increase the number of market actors, which will increase the complexity of managing the electricity markets.

Thus, a new market entity, an aggregator, will be required in order to enable smooth cooperation between storage owners and SO. The economic incentive of the aggregator is to increase its revenue by buying/selling the electric power at the lowest/highest possible price to satisfy driving needs of its fleet of EVs [48] and [50]. Having a flexible power source, storage aggregator can provide balancing power and increase its profit.

A stationary EES unit can act as a generator or a consumer, while interacting with the electric grid. In a similar way, the EV interaction with the grid can be categorized as unidirectional or bidirectional. The unidirectional mode results in lower flexibility and profits, however it does not increase the cycling tear of the battery [51]. In contrast, as references [52]-[54] show, the bidirectional mode offers higher flexibility and profits, while reducing the battery lifetime. Therefore, storage owners must be compensated for the lost utility of their batteries, due to degradation when providing the ASs [55].

An EES units aggregator will participate in SmartNet market (AS market) on behalf of the EES owner, aiming to maximize its profit. To summarize all thoughts above, the EES units aggregation model is a profit maximizing optimization problem, where a linear programming (LP) can be used as a mathematical tool. LP results in a convex feasible region. Therefore, the global optimal solution can always be reached.

On one hand, the EES unit aggregation model is non-linear, because the charging and discharging efficiencies depend on the charging and discharging power. On the other hand, taking into consideration

the uncertain nature of market conditions and fleet characteristics, stochastic approach fits better for the aggregator's optimal bidding problem. However, it is computationally hard to solve non-linear stochastic model for the following reasons; 1) global optimal solution cannot be guaranteed with a non-linear model 2) the computational complexity gets worse with increasing number of scenarios. This complexity level is out of the scope of SmartNet project. Therefore, the non-linear, stochastic EES units aggregation model is approximated its linear deterministic counterpart.

The rest of this section is structured as follows: The section 5.4.1 describes the flexibility cost components of the aggregated EES units. The section 5.4.2 describes the aggregator's optimal bidding strategy. The section 5.4.3 describes an algorithm to provide flexibility bids in both directions for every time step.

5.4.1 Flexibility Cost Components

As it has been explained above, the EES unit is a suitable source for providing regulating service accounting on its capability to increase or decrease generation/consumption very fast.

The EES unit flexibility costs participating in SmartNet market (ancillary markets) include 1) **commitment cost** 2) **market discomfort cost** and 3) **degradation cost**.

The commitment cost refers to aggregator's offer to the EES' owner to participate in SmartNet market while providing upward/downward flexibility. Let's assume C [€/MWh] is the commitment cost. Please note that, when the EES unit is discharging the aggregator buys X [MWh] of electric energy form the EES owner with C [€/MWh] commitment cost and sells to the SmartNet market with the estimated SmartNet market price. Therefore, in this case X [MWh]* C [€/MWh] is a cost for the aggregator. However, when the EES unit is charging the aggregator buys X [MWh] of electric energy form the SmartNet market with the estimated SmartNet market price and sells to the EES owner with C [€/MWh] commitment cost. Thus, here X [MWh]* C [€/MWh] is a profit for the aggregator.

Market discomfort cost refers to the tradeoff cost to sell/buy electric power now at the SmartNet market or wait for the future intra-day opportunities.

Degradation cost refers to the aging/operational cost while using the EES devices for grid purposes. When providing ancillary services the lifetime of an EES unit reduces. Hence, the EES owner must be compensated for the lost functionality due to degradation while participating in the SmartNet market. This is a cost for the aggregator, which will decrease the profit.

5.4.2 The EES Units Aggregator's Optimal Aggregation Strategy

The optimal strategy for an EES units aggregator, participating in the SmartNet balancing market, is presented below.

5.4.2.1 Nomenclature

A. Indices

k	Index of storage, $k = 1, \dots, K$
t	Planning periods, $t = 1, \dots, T$
m	Index for cycles in rolling planning, $m = 1, \dots, M$

B. Parameters

P_k^{maxdch}	Maximum rate of discharge for an EES
P_k^{mindch}	Minimum rate of discharge for an EES
P_k^{maxch}	Maximum rate of charge for an EES
P_k^{minch}	Minimum rate of charge for an EES
E_k^{max}	Maximum capacity of an EES
γ_k^{max}	Scalar to calculate maximum SoC
γ_k^{min}	Scalar to calculate minimum SoC
$R_k^{maxRU/RDdc}$	Ramp up/down rating of an EES while discharging
$R_k^{maxRU/RDch}$	Ramp up/down rating of an EES while charging
$p_{k,t}^{ch}$	Offered charge amount in the previous market
$p_{k,t}^{dch}$	Offered discharge amount in the previous market
η_k^{ch}	Charging efficiency of an EES
η_k^{dch}	Discharging efficiency of an EES
Δt	Time duration of each time step
$SoC_{k,t=0}^{B}$	EES level at the beginning of the planning period
SoC_k^{Bend}	EES level at the end of the planning period T
λ_t	Realized/estimated market prices from the last intraday market
RC_t	Time varying random market discomfort cost
c	Commitment cost; aggregator's offer to an EES' owner
c_k^{cap}	Capital cost of an EES
μ_k	The slope of the linear approximation of the battery life as a function of the cycles
$A_{k,t}$	Availability matrix indicating whether an EES is available, or not, for a specific time step t
D_k	Average hourly driving distance of an EV
η_k^{dr}	Driving efficiency of an EV

C. Variables

$p_{k,t}^{Bch}$	Balancing market charge dispatch level for k^{th} EES
$p_{k,t}^{Bdch}$	Balancing market discharge dispatch level for k^{th} EES
AP_t^{Bdch}	Aggregated discharge volume per time step t
AP_t^{Bch}	Aggregated charge volume per time step t
$SoC_{k,t}^{B}$	EES level at the end of time step t

5.4.2.2 Objective Function

The optimization problem stated in (81) aims at maximizing the aggregator's profit from the SmartNet market power exchange.

$$\text{Maximize } \sum_{t=1}^{T}\sum_{k=1}^{K}\Bigg[\left((\lambda_t - RC_t)\, p_{k,t}^{Bdch}\Delta t - c\,\frac{p_{k,t}^{Bdch}}{\eta_k^{dch}}\Delta t - \left|\frac{\mu_k}{100}\right|\frac{c_k^{cap}}{E_k^{max}}\, p_{k,t}^{Bdch}\Delta t\right) - \left((\lambda_t + RC_t)\, p_{k,t}^{Bch}\Delta t - c\,\eta_k^{ch} p_{k,t}^{Bch}\Delta t + \left|\frac{\mu_k}{100}\right|\frac{c_k^{cap}}{E_k^{max}}\, p_{k,t}^{Bch}\Delta t\right)\Bigg] \quad (81)$$

The first line of (81) formulates the aggregator's profit (revenue minus cost) while providing discharge bids. The second line of (81) expresses the aggregator's profit (revenue minus cost) when offering charge bids. Please note that, to offer discharging bids to the SmartNet market the aggregator needs to buy electric power from the EES owner with the agreed price and sell it to SO with the estimated SmartNet price. In contrast, to provide a charging bids, the aggregator need to buy electric power form the SO with the estimated SmartNet market price and sell it to the EES owner with the agreed price. Note that for both cases the aggregator accounts for the degradation cost of the EES unit. It is obvious that the SmartNet market price is estimated as the difference of the price of the last cleared market and the market discomfort cost. The market discomfort cost RC_t is calculated according to (5), Chapter 3.

5.4.2.3 Constraints

SoC balance constraint can be modeled as:

$$SoC_{k,t}^{B} = SoC_{k,t-1}^{B} + \left[p_{k,t}^{ch}\,\Delta t\eta_k^{ch} - \frac{p_{k,t}^{dch}}{\eta_k^{dch}}\Delta t + p_{k,t}^{Bch}\Delta t\eta_k^{ch} - \frac{p_{k,t}^{Bdch}}{\eta_k^{dch}}\Delta t\right]A_{k,t} - D_k\Delta t\eta_k^{dr}\left(1 - A_{k,t}\right) \quad (82)$$

Equation (82) states that for each hour the new content of the storage is equal to its old content plus energy inflow minus energy outflow. Please note that, (82) allows modeling both stationary and mobile (EV) storages. For stationary storages, the availability matrix $A_{k,t}$ is always 1; hence the last term which is energy spend on driving purposes vanishes. For EVs the availability matrix is either 0 or 1 depending on weather the EV is available or on a trip.

The storage level is bounded by its minimum and maximum levels (83).

$$\gamma_k^{min} E_k^{max} \leq SoC_{k,t}^{B} \leq \gamma_k^{max} E_k^{max} \tag{83}$$

The constrains (84) and (85) define flexibility level for charge/discharge based on the maximum device discharge/charge capacity and the device commitment in the previous markets. Note that if the device is not available the flexibility level will be forced to be 0 according to (84) and (85).

$$A_{k,t} P_k^{mindch} \leq p_{k,t}^{Bdch} \leq (P_k^{maxdch} - p_{k,t}^{dch} + p_k^{ch}) A_{k,t} \tag{84}$$

$$A_{k,t} P_k^{minch} \leq p_{k,t}^{Bch} \leq (P_k^{maxch} - p_{k,t}^{ch} + p_k^{dch}) A_{k,t} \tag{85}$$

Constraints (86) and (87) limit the rate of storage discharging and charging between any two successive hours.

$$-R_k^{maxRDdch} \leq \left(p_k^{dch} + p_{k,t}^{Bdch}\right) - \left(p_{k,t-1}^{dch} + p_{k,t-1}^{Bdch}\right) \leq R_k^{maxRUdch} \tag{86}$$

$$-R_k^{maxRDch} \leq \left(p_k^{ch} + p_{k,t}^{Bch}\right) - \left(p_{k,t-1}^{ch} + p_{k,t-1}^{Bch}\right) \leq R_k^{maxRUch} \tag{87}$$

As state before in the deliverable, a general model is used for the aggregation of EES units, which enables merging different types of EES technologies. For some EES technologies, the ramp rate constraints can be less important.

The constraint (88) makes sure that an EV will have a desired SoC, before leaving for a trip.

$$SoC_{k,T}^{B} \geq SoC_k^{B_{end}} \tag{88}$$

An alternative way of modelling the end SoC could be by fixing SoC at the end of the planning period and penalizing the deviation of the end SoC from the desired end SoC in the objective function. However, modelling SoC at the end of the planning period, as in (88), ensures fulfilling the desired SoC level[20] and provides more flexibility to the system (if the battery is not full the EES unit can store more than the desired level providing down-regulating flexibility).

Finally, the equations (89) and (90) aggregate charge/discharge power.

$$\sum_{k=1}^{K} p_{k,t}^{Bdch} = AP_t^{Bdch} \tag{89}$$

$$\sum_{k=1}^{K} p_{k,t}^{Bch} = AP_t^{Bch} \tag{90}$$

[20] Please note that, the desired level of SoC is highly dependent on the diurnal availability patterns of a particular EV.

5.4.2.4 Rolling Planning

The information about the SmartNet market (balancing markets), as well as the availability of an EV, are revealed continuously. In order to benefit from the information released over time, the forecasted parameters can be updated with the arrival of new information. Let $\Omega[\mathrm{t}, T_m]$ be the decision tree predictions for time steps t to T using the historical data up to time step t for the simulation cycle m. In the rolling planning, the $\Omega[\mathrm{t}, T_m]$ can be dynamically updated by the SmartNet market prices and EV availability revealed until hour t. Ideally, we can update the forecast for every time step t, which we call *simulation cycle*. For each simulation cycle, the corresponding storage parameters are re-forecasted and the entire simulation is re-run. Figure 5.28 shows the scheme of the decision process for the forecasted SmartNet prices and EV availability. The arrows show the time duration, while the black circles represent decisions made by the producer/consumer.

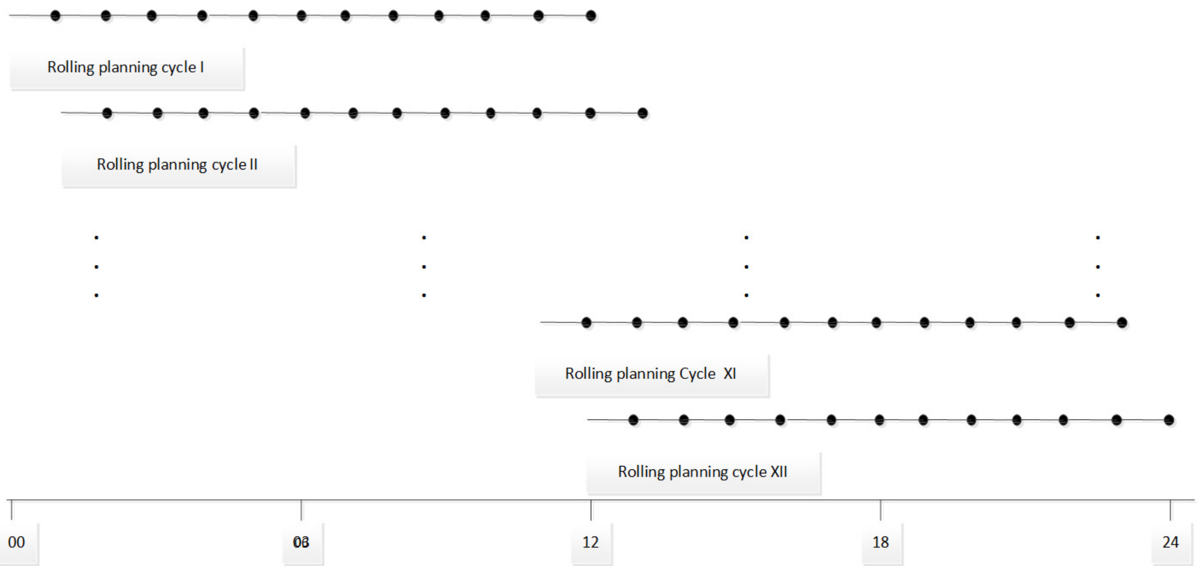


Figure 5.28 Decision process scheme

5.4.2.5 The EES Units Aggregation Optimization Problem

The EES aggregator solves the problem stated below, using LP, in order to derive optimal bidding strategy; the optimal bidding curves in the SmartNet market.

$$\text{Maximize}_{\Phi} \sum_{t=1}^{T_m} \sum_{k=1}^{K} \Bigg[\left((\lambda_t - RC_t)\, p_{k,t}^{Bdch} \Delta t - c\, \frac{p_{k,t}^{Bdch}}{\eta_k^{dch}} \Delta t - \left| \frac{\mu_k}{100} \right| \frac{c_k^{cap}}{E_k^{max}} p_{k,t}^{Bdch} \Delta t \right) - \left((\lambda_t + RC_t)\, p_{k,t}^{Bch} \Delta t - c\, \eta_k^{ch} p_{k,t}^{Bch} \Delta t + \left| \frac{\mu_k}{100} \right| \frac{c_k^{cap}}{E_k^{max}} p_{k,t}^{Bch} \Delta t \right) \Bigg] \tag{91}$$

subject to (82)-(90), where $\Phi\{p_{k,t}^{Bdch}, p_{k,t}^{Bch}, SoC_{k,t}^{B},\ AP_t^{Bdch}, AP_t^{Bch} \geq 0\}$.

5.4.3 An Algorithm for EES Units Aggregation - for Preparing Bids in Both Directions

The EES units aggregator can offer bids in both upward and downward directions for every time step. Depending on the market needs either an up-regulated or a down-regulated bid will be activated by the SO. Therefore, an algorithm has been developed to make it possible to generate optimal bids in both directions for each time step. Please note that the aggregator will be willing to provide bids in both directions only if it is profitable.

The price driven optimal solution derived from the optimization problem stated in section 5.4.2.5 for each bidding step *t*, may belong to one of the following 4 states: (1) both discharging and charging bids are equal to 0, (2) only discharging bid is greater than 0, (3) only charging bid is greater than 0, (4) both discharging and charging bids are greater than 0. It is obvious that the estimated market prices are not always beneficial for the aggregator, for it to offer bids in both directions, even if the flexibility exists. Let us assume that the optimal solution from the optimization model for a specific time step *t* is in state (2). Hence, for this time step a bid offered at an estimated market clearing price is only optimal for discharging. However, if the aggregator gets a lower price offer from the SO for charging, it will also provide charging bid, according to the flexibility margin. It is up to the aggregator how to define a cheaper price. For example, it can be half of the estimated market price, or even zero. Therefore, for this example time step, the aggregator will submit **a discharge bid** received from the optimization model **at the estimated SmartNet market price** and **a charge bid** according to the availability margin, **at lower price than the estimated SmartNet market price.** In a similar way, the opposite direction bids are generated for those time steps when the price driven optimal solution, resulted from the optimization problem, is in state (1), (3) or (4). Figure 5.29 shows the flowchart of the aggregation algorithm for deriving the optimal bids. Figure 5.30 illustrates an optimal bid curve in both upward and downward directions for an example time step. The optimal bid volume in both upward and downward directions for a particular EES unit is calculated taking into consideration the maximum capacity of the device, and its commitment to the previous markets.

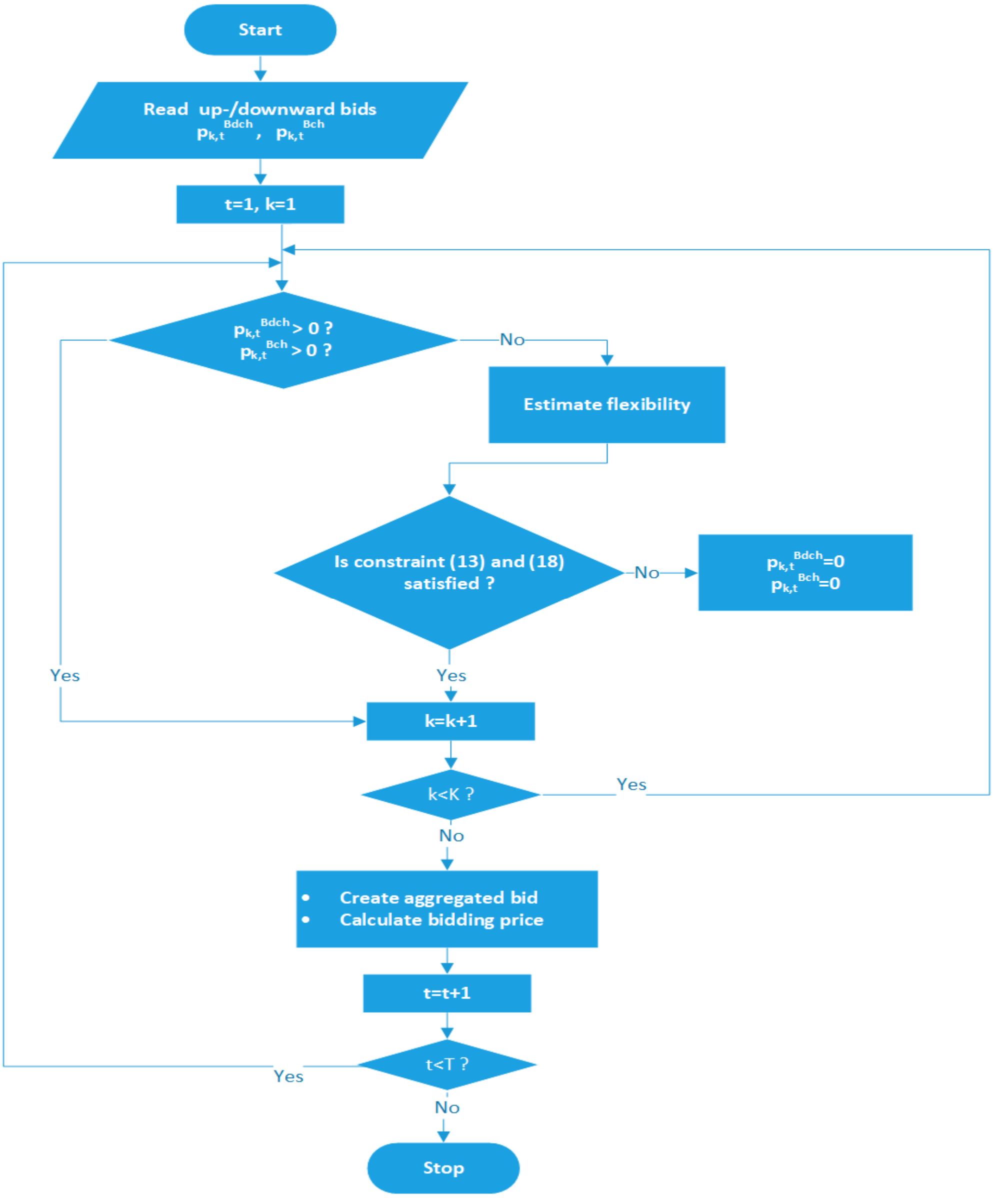


Figure 5.29 Flowchart of the proposed algorithm for deriving upward/downward bids

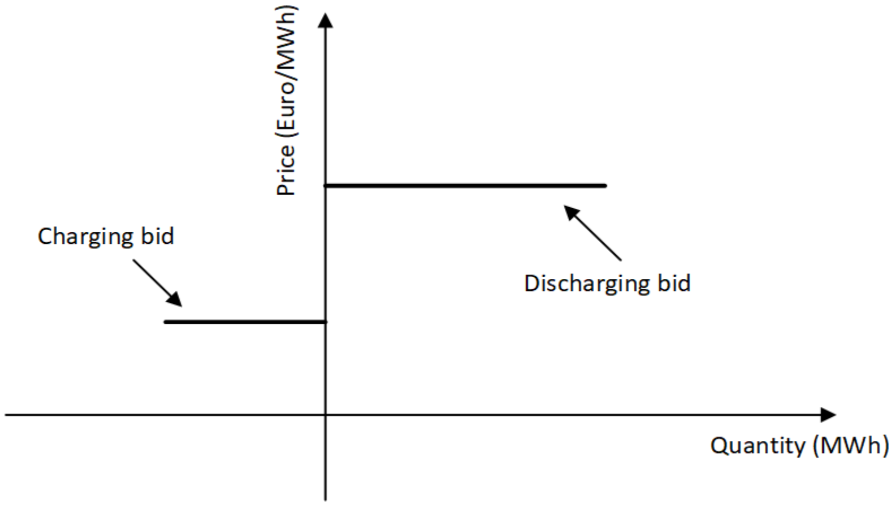


Figure 5.30 An optimal bid curve in both upward and downward directions for an example time step

5.4.3.1 Reactive Power Capability of EES Units

The grid coupling technology supporting a connection of a stationary EES to the electric network defines the reactive power capability of a EES unit. According to [4], grid coupling technologies for a EES system can be categorized 1) circular capability (grid coupling with inverters) 2) rectangular capability (rotating machine direct coupling).

Depending on whether an EV is available, or not, the EV reactive power capability can be circular or half-circular [56].

5.5 Curtailable Generation and Curtailable Loads

This section describes the aggregation model for curtailable generation (wind, PVs and small-scale hydropower) and curtailable loads.

5.5.1 Curtailable Generation

Curtailment can be defined as a case, when a non-dispatchable generation unit produces less than it could. Curtailment can be voluntary or involuntary, as for example enforced by TSO. Several most common reasons for curtailment can be pointed out [52]:

- Network technical constraints. In order to avoid overinvestment in the transmission and distribution infrastructure.
- Operational security. This is not related to the capacity, but other limitations as reactive power, grid faults, voltage magnitude limitations and possible voltage collapse, and similar.
- Excess generation with respect to the grid load.
- Strategic bidding, related to potential price manipulations.

5.5.1.1 Wind Power and PV Generation

5.5.1.1.1 Availability of Wind and PV Generation

The availability of wind does not only define when the power can be generated, but also the ability to adjust the generated output [57]. The same can be applied to PV generation as another RES with fluctuating nature. In the context of the SmartNet project, this means that the volume of bids submitted by wind and PV generation should correspond to the available generation potential at a given time. Wind speeds and solar radiation vary over time and can be predicted only to a certain extent.

PV generation provides a possibility of full or partial down-regulation by reducing the volume of injected electricity. Down-regulation is also used for wind power. Wind turbine generators with fixed pitch systems must be shut down completely by braking and opening the circuit breaker i.e. on/off. By controlling the pitch of the wind turbine blades, the power output can be curtailed partially, even though some sources point out that this increases the wear and tear significantly.

There are some test projects [58] studying the possibility for using wind power for upward-regulation. In the project's time horizon it is however reasonable to assume that wind power can be used for both up- and down-regulation. It can be concluded that:

- Wind and PV generation can provide full or partial down-regulation capacity according to available generation potential at the given moment.

- Depending on the technology, wind generators and PV can reduce their output and thus provide curtailment services (in the UK, it is also called intertrip service by National Grid).

5.5.1.1.2 Costs for Wind and PV Generation

Due to absence of fuel costs, generation costs for PV and wind power reflect the variable O&M costs, as described in Section 2.4.1 in the deliverable D1.2 [4]. These can vary from close to zero (PV systems without tracking) to higher values. Additionally, in order to increase the share of RES, several subsidies have been introduced. The most common form of subsidies in Europe today are fixed feed-in tariffs – administratively setting a tariff for every MWh produced over a given period – while some other countries practice Green Certificates as another form of subsidies. Detailed description and evaluation of different support schemes to RES are explained in [59]. Even though it is currently a subject of discussion, it is quite unlikely that the subsidies will be discontinued within the next 15–20 years (see recommendations from Market4RES project [60]). It is however possible that the design of the present support schemes can be changed, where feed-in premium is one of the most probable alternatives.

5.5.1.2 Small-scale Hydropower

Small-scale hydropower is operated in some European countries with favorable landscape and climate conditions, as for example Norway or Austria. There are several hundreds of small-scale hydropower installations in Norway, some of them only 20–30 kW. The installations are operated by independent owners or, in some cases, by power generating companies. The majority of small-scale hydropower installations are situated in mountainous areas and have reservoirs providing enough flexibility to cover seasonal variations in precipitation and water flow during the major part of the year.

Considering that hydropower plants using reservoirs, i.e. PHES, are considered in Section 5.4, this aggregation model considers only small-scale run-of-river hydropower with no reservoir, meaning that in case of generation curtailment, the major part of water is lost. These units are, therefore, normally operated on full capacity, and for the sake of simplicity, it can be assumed that they can be down-regulated fully or partially.[21]

5.5.2 Curtailable Loads

In this section, loads that can be curtailed without *rebound effects* are considered. These are described in Section 2.4.8 in the deliverable D1.2 [4]. This means that, at a later time, there is no need for making up for the load being curtailed. An example of a load *with* a rebound effect is the heating of a swimming pool.

[21] Many hydropower plants have some minimum power that is above zero. They can be down-regulated to any power above this limit, or stopped. Despite that, accurate modelling of DERs is found rather complex, time consuming, and mostly unnecessary for the studies in SmartNet.

Once power has been cut, the pool gradually dissipates heat, and more power than usual is needed to get the pool back to normal temperature. An example of a load *without* rebound effect is electric lighting, such as household lightning, commercial building or industries lightning and even outdoor lighting. Other examples include some industrial processes when the production level is not required to be strictly maintained. Even if the light is reduced or switched off, there is no need for increasing the light level above nominal in the future when standard power supply returns.

5.5.3 Mathematical Model of Flexibility Intervals

This section defines the flexibilities of single and aggregated devices. It is assumed that no ramping constraints apply for curtailable generation or curtailable loads, as the change of power generation/consumption is much faster than the time scale considered in the SmartNet project [4].

5.5.3.1 Flexibility of a Single Device

List of symbols

$\hat{}$	External viewpoint variable
$F_{r,t}$	Flexibility interval of device r at time step t
$F^{-}_{r,t}$	Downward flexibility interval of device r at time step t
$F^{+}_{r,t}$	Upward flexibility interval of device r at time step t
$O_{\text{agg},t}$	Aggregated operational interval at time step t
$O_{r,t}$	Operational interval of device r at time step t
$P^{\text{base}}_{\text{agg},t}$	Aggregated baseline at time step t
$P^{\text{flex},-}_{\text{agg},t}$	Downward aggregated flexibility at time step t
$P^{\text{flex},+}_{\text{agg},t}$	Upward aggregated flexibility at time step t
$P^{\text{hi}}_{\text{agg},t}$	Upper boundary of the aggregated operational interval $O_{\text{agg},t}$
$P^{\text{lo}}_{\text{agg},t}$	Lower boundary of the aggregated operational interval $O_{\text{agg},t}$
$P^{\text{base}}_{r,t}$	Baseline power of device r at time step t, which is an output, obtained from the previous market clearing, i.e. day-ahead or intraday
$P^{\text{flex},-}_{r,t}$	Downward flexibility of device r at time step t
$P^{\text{flex},+}_{r,t}$	Upward flexibility of device r at time step t
$P^{\text{hi}}_{r,t}$	Upper boundary of the operational interval $O_{r,t}$
$P^{\text{in}}_{r,t}$	Inflow power which reflects the best available forecast of actual wind, water or sun availability of device r at time step t
$P^{\text{lo}}_{r,t}$	Lower boundary of the operational interval $O_{r,t}$
$P^{\text{out}}_{r,t}$	Actual power output of device r at time step t
P^{max}_{r}	Maximum power output of device r, determined by the device's maximum installed capacity
P^{min}_{r}	Minimum power output of device r
n_D	Number of loads
n_G	Number of generators
Δt	Length of time step
d	Index of load
g	Index of generator
r	Index of unified device
t	Time step number

5.5.3.1.1 Curtailable Generation

A collection of wind generators, numbered from 1 to n_G would be a good example of curtailable generators to keep in mind in this section. In the following, $1 \leq g \leq n_G$.

The inflow power of generator number g at time step t, denoted as $P_{g,t}^{\text{in}}$, is converted by the generator to the actual power output $P_{g,t}^{\text{out}}$, which can never exceed the maximum power output $P_g^{\max}$ (or the inflow power at time t). The *operational interval* $O_{g,t}$ is defined as the interval that the actual power output $P_{g,t}^{\text{out}}$ must be within, because of the physical constraints. Although it is expected that the baseline power $P_{g,t}^{\text{base}}$ would normally be inside the operational interval, instances when this is not true may arise, e.g. if the wind speed is much lower than what was predicted when submitting offers in the previous market.

Figure 5.31 shows three different situations that could arise for a curtailable generator:

a) The case in which the inflow is larger than the maximum output of the generator. The operational interval is then $O_{g,t} = [0, P_g^{\max}]$, and the baseline lies inside it.
b) The case in which the baseline is lower than the inflow, and both inflow and baseline power are lower than the maximum output. Then, the operational interval is $O_{g,t} = [0, P_{g,t}^{\text{in}}]$, with the baseline power inside the operational interval.
c) The case in which the inflow power is lower than the baseline, so the operational interval is $O_{g,t} = [0, P_{g,t}^{\text{in}}]$. In this case, the baseline is outside the operational interval.

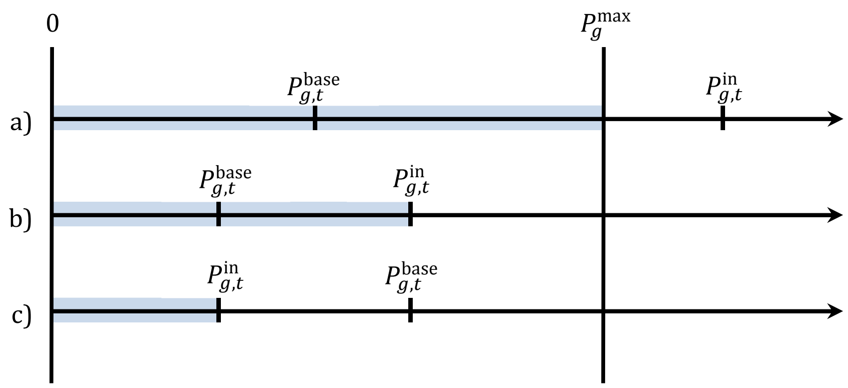


Figure 5.31 All possible combinations of baseline and inflow. Operational intervals $O_{g,t}$ are shaded blue.

The operational interval of the device needs to be defined in order to incorporate the operational intervals of all three cases, namely

$$O_{g,t} = [0, \min(P_g^{\max}, P_{g,t}^{\text{in}})], \qquad \text{or} \qquad 0 \leq P_{g,t}^{\text{out}} \leq \min(P_g^{\max}, P_{g,t}^{\text{in}}). \tag{92}$$

If generators wish to participate in the provision of flexibility via curtailment, the operational interval needs to take into consideration the baseline generation output $P_{g,t}^{\text{base}}$ from the previous market. Therefore, the *flexibility interval*, i.e. the operational interval relative to $P_{g,t}^{\text{base}}$, can be defined as:

$$F_{g,t} = [-P_{g,t}^{\text{base}}, \min(P_g^{\max}, P_{g,t}^{\text{in}}) - P_{g,t}^{\text{base}}]. \tag{93}$$

To distinguish between flexibility provided via increased (which is sometimes also possible) and decreased generation levels, *upward and downward flexibility intervals* $F_{g,t}^{+}$ and $F_{g,t}^{-}$ are defined as the

closed subintervals of $F_{g,t}$ that lie above and below zero, respectively. Zero corresponds to the baseline power. This means that the upward and downward flexibility intervals consist of all the physically realizable power output values relative to the baseline. Providing zero flexibility means that the power output is equal to the baseline power.

If $0 \in F_{g,t}$, i.e. if the baseline is physically attainable, the *upward and downward flexibilities* can be defined as the maximum possible deviation from the baseline in each direction:

$$P_{g,t}^{\text{flex},+} = \min\left(P_g^{\max}, P_{g,t}^{\text{in}}\right) - P_{g,t}^{\text{base}}, \tag{94}$$

$$P_{g,t}^{\text{flex},-} = -P_{g,t}^{\text{base}}. \tag{95}$$

The upward flexibility is positive, and the downward flexibility is negative. Conversely, if $0 \notin F_{g,t}$, i.e. if the baseline is *not* physically attainable, $P_{g,t}^{\text{flex},+}$ and $P_{g,t}^{\text{flex},-}$ will both become either positive or negative, which does not make sense when talking about upward and downward flexibilities. Thus, in this case, upward and downward flexibilities are *not defined*, but upward and downward flexibility intervals are still valid, though.

For a curtailable generator, it is always more profitable to inject the available generation capacity (the inflow power) into the grid and therefore, the curtailable generator would always be able to offer only downward flexibility. However, under certain system's conditions, curtailable generators could be operated in the curtailment mode on the demand of the SO. In this case, the generator would be able to offer upward flexibility as well, which is captured by cases a and b in Figure 5.31.

Due to the variable nature of the output of curtailable generation, the forecast of the output is increasingly unreliable with time and the curtailable generator is not capable of guaranteeing the baseline production traded in the previous markets. This could lead to the situation when the power baseline is higher than the inflow power (case c in Figure 5.31). However, having assumed that there is a mechanism for continuous trading in the intraday market, the baseline power should always be considered aligned with the most updated forecast. Therefore, the situation in which the baseline profile is higher than the inflow power (case c in Figure 5.31) will not be simulated and should not be considered as a practically relevant scenario.

5.5.3.1.1.1 Example: Flexibility Intervals

In this example, the flexibility for a wind generator g with $P_g^{\max} = 1200$ kW is calculated. Under the assumption that the power inflow is $P_{g,t}^{\text{in}} = 1000$ kW, the operational interval becomes

$$O_{g,t} = [0, \min(1000, 1200)]\ \text{kW} = [0, 1000]\ \text{kW}. \tag{96}$$

Assume first that the baseline is *inside* the operational interval (cases a and b in Figure 5.31), e.g. $P_{g,t}^{\text{base}} = 400$ kW. Then the flexibility interval becomes $F_{g,t} = [-400, 600]\ kW$, the upward flexibility

interval becomes $F_{g,t}^{+} = [0, 600]$ kW, and the downward flexibility interval becomes $F_{g,t}^{-} = [-400, 0]$ kW. The upward and downward flexibilities are $P_{g,t}^{\text{flex},+} = 600$ kW and $P_{g,t}^{\text{flex},-} = -400$ kW.

5.5.3.1.2 Curtailable Loads

The loads are numbered in the same way as for the generators, $1 \leq d \leq n_D$, where n_D is the number of loads.

To avoid confusion about different sign conventions, two different viewpoints are presented in this section. The first one, called the external viewpoint, will seem the most natural one when considering the input data. The external viewpoint is denoted by hatted variables. For example, the maximum power consumption of a load is a positive number denoted by $\hat{P}_d^{\max}$.

The second viewpoint, called the internal viewpoint, has a different sign convention, and is employed internally in calculations. Here, the maximum power consumption of a load is a negative number denoted by $P_d^{\min} = -\hat{P}_d^{\max}$. Similarly, the minimum power consumption of a load is a negative number denoted by $P_d^{\max} = -\hat{P}_d^{\min}$. The internal viewpoint is necessary in order to construct a unified device model, which combines the generation and consumption, as in Section 5.5.3.1.3.

For generators, the key power variable is the power output $P_{g,t}^{\text{out}}$, and there is a similar notion for loads, namely the power consumption $\hat{P}_{d,t}^{\text{con}}$. Power consumption is defined as the amount of power that the load draws from the grid. In the internal viewpoint, loads are treated in the same way as generators, so they also have a power output $P_{d,t}^{\text{out}}$, but since loads consume power from the grid instead of supplying to it, this number is negative, $P_{d,t}^{\text{out}} = -\hat{P}_{d,t}^{\text{con}}$. This means that for load number d at time step t, both power output $P_{d,t}^{\text{out}}$ and baseline $P_{d,t}^{\text{base}} = -\hat{P}_{d,t}^{\text{base}}$ become negative (or rather, non-positive, as they can have a value of zero).

In the next paragraphs, operational and flexibility intervals are defined for loads, but only for the internal viewpoint. The external viewpoint should be considered as a translation layer between the input data and the internal variables.

A single curtailable load with baseline $P_{d,t}^{\text{base}} < 0$, maximum power consumption $P_d^{\min}$, and minimum power consumption $P_d^{\max}$ is considered. Being in line with the notation used in the previous section used for generation, the operational interval for load d and time t becomes

$$O_{d,t} = [P_d^{\min}, P_d^{\max}], \tag{97}$$

and the flexibility interval becomes

$$F_{d,t} = \left[P_d^{\min} - P_{d,t}^{\text{base}}, P_d^{\max} - P_{d,t}^{\text{base}}\right]. \tag{98}$$

For loads, the baseline will always be inside the operational interval, so the upward and downward flexibilities can be defined as

$$P_{d,t}^{\text{flex},+} = P_d^{\max} - P_{d,t}^{\text{base}}, \tag{99}$$
$$P_{d,t}^{\text{flex},-} = P_d^{\min} - P_{d,t}^{\text{base}}. \tag{100}$$

5.5.3.1.3 Unified Model

Curtailable generators and curtailable loads can be combined into a single unified power device model, by using negative values for power output when electricity is consumed by the device, and positive values when it is supplied by the device.

In the same way as in the previous two sections, the operational interval can be defined, which for a device r, and time t becomes

$$O_{r,t} = \left[P_r^{\min}, \min\left(P_r^{\max}, P_{r,t}^{\text{in}}\right)\right] \tag{101}$$

This covers both generators and loads by simply setting either $P_r^{\min}$ or $P_{r,t}^{\text{in}}$ to zero. The flexibility interval becomes

$$F_{r,t} = \left[P_r^{\min} - P_{r,t}^{\text{base}}, \min\left(P_r^{\max}, P_{r,t}^{\text{in}}\right) - P_{r,t}^{\text{base}}\right]. \tag{102}$$

If $P_{r,t}^{\text{base}} \in O_{r,t}$, the upward and downward flexibilities can be calculated as

$$P_{r,t}^{\text{flex},+} = \min\left(P_r^{\max}, P_{r,t}^{\text{in}}\right) - P_{r,t}^{\text{base}}, \tag{103}$$
$$P_{r,t}^{\text{flex},-} = P_r^{\min} - P_{r,t}^{\text{base}}. \tag{104}$$

Figure 5.32 shows an example based on a unified model device and shows all possible operational intervals for several time steps simultaneously. The intervals are combined into a single *operational envelope* shown in the figure as a blue shaded area. There are several things worth mentioning here. Any path for $P_{r,t}^{\text{out}}$, which is inside the operational envelope, can be offered on the market. The upward and downward flexibilities are illustrated in time step 5. However, there is also a situation where the upward flexibility interval becomes the empty set, when $P_{r,t}^{\text{in}}$ passes below $P_{r,t}^{\text{base}}$, which is the case in time steps 3 and 4.

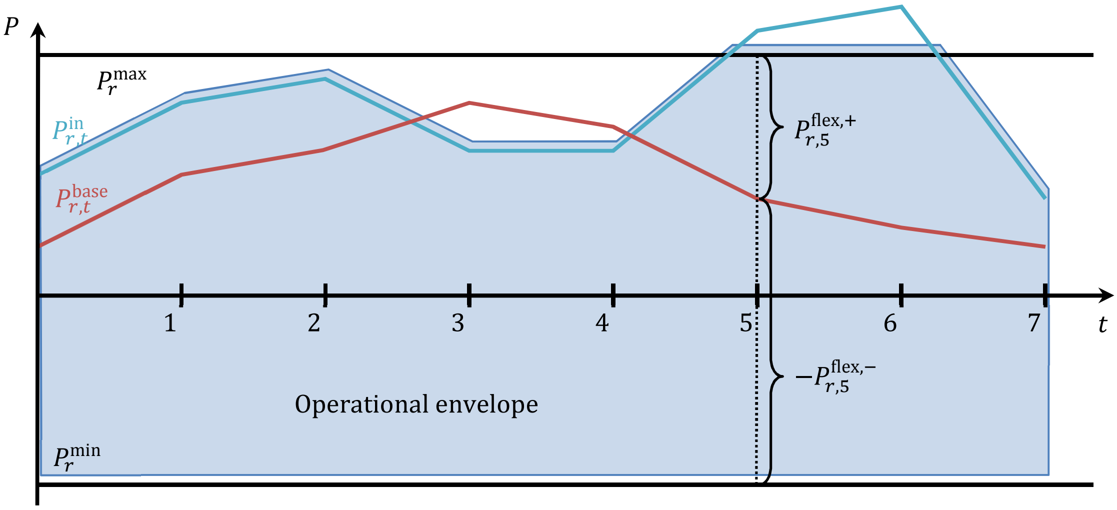


Figure 5.32 Operational envelope of a single unified device. Any path for $P_{r,t}^{\text{out}}$ which is inside the operational envelope (shaded), can be offered on the market.

5.5.3.2 Flexibility of Aggregated Devices

This section explains the aggregation of flexibility. It is assumed that all the devices that are aggregated can be described using the unified model from Section 5.5.3.1.3. Consider n_R such devices, i.e. $r = 1, \dots, n_R$, at time interval t, and each of them having operational interval $O_{r,t} = [P_{r,t}^{\text{lo}}, P_{r,t}^{\text{hi}}]$. The aggregated operational interval $O_{\text{agg},t}$ combines the operational intervals of all the devices. It can be considered as the total range of power output that the devices can deliver/absorb together,

$$O_{\text{agg},t} = \left[P_{\text{agg},t}^{\text{lo}}, P_{\text{agg},t}^{\text{hi}}\right] = \left[\sum_{r=1}^{n_R} P_{r,t}^{\text{lo}}, \sum_{r=1}^{n_R} P_{r,t}^{\text{hi}}\right]. \tag{105}$$

An aggregated operational envelope can be constructed just as in Section 5.5.3.1.3.

As for the single device models, the aggregated baseline $P_{\text{agg},t}^{\text{base}} = \sum_{r=1}^{n_R} P_{r,t}^{\text{base}}$ can be either inside or outside the aggregated operational interval. For the case where $P_{\text{agg},t}^{\text{base}} \in O_{\text{agg},t}$, the upward and downward aggregated flexibilities can be calculated:

$$P_{\text{agg},t}^{\text{flex},+} = P_{\text{agg},t}^{\text{hi}} - P_{\text{agg},t}^{\text{base}}, \tag{106}$$

$$P_{\text{agg},t}^{\text{flex},-} = P_{\text{agg},t}^{\text{lo}} - P_{\text{agg},t}^{\text{base}}. \tag{107}$$

5.5.4 Flexibility Cost

The following sections define flexibility costs of curtailable generation and load curtailment as well as their unified model. Note that not all of the components of the flexibility cost, explained in Chapter 2, apply to curtailable generation and load curtailment.

List of symbols

$P^{\mathrm{d}}_{r,t}$	The power output that device r desires at time step t
$P^{\mathrm{flex}}_{r,t}$	Activated flexibility of device r at time step t
$c^{\mathrm{dis}}_{r,t}$	Discomfort cost associated to $P^{\mathrm{flex}}_{r,t}$
n_R	Number of unified devices
$c^{\mathrm{flex}}_{r,t}$	Price of flexibility of device r at time step t
$\lambda^{\mathrm{dis}}_{r,t}$	Marginal discomfort cost of device r at time step t
$\lambda^{\mathrm{flex}}_{r,t}$	Marginal flexibility cost of device r at time step t
$\lambda^{\mathrm{rev}}_{r,t}$	Marginal revenue from product sales of device r at time step t
$\lambda^{\mathrm{sub}}_{r,t}$	Marginal revenue from subsidies of device r at time step t
$\lambda^{\mathrm{O\&M}}_{r,t}$	Marginal O&M cost of device r at time step t
$\lambda^{\mathrm{el}}_{t}$	Marginal cost of electricity at time step t
$\pi^{\mathrm{base}}_{r,t}$	Profit of device r after previous market at time step t
$\pi^{\mathrm{flex}}_{r,t}$	Profit of device r after current market at time step t
D	Set of indices of loads
G	Set of indices of generators
R	Set of indices of unified devices

5.5.4.1 Flexibility Cost of Curtailable Generation

A curtailable generator's flexibility cost equals the cost of adjusting the output from the level decided in the previous market (i.e. the day-ahead or intraday market), $P^{\mathrm{base}}_{g,t}$, to the output of the current market (i.e. the flexibility market), $P^{\mathrm{out}}_{g,t}$. The difference between these output levels is the activated flexibility $P^{\mathrm{flex}}_{g,t} = P^{\mathrm{out}}_{g,t} - P^{\mathrm{base}}_{g,t}$, i.e. $P^{\mathrm{flex}}_{g,t}$ is in the flexibility interval $F_{g,t}$ (see (93)). The goal of this section is to find a formula for the extra cost for the generator for providing flexibility $P^{\mathrm{flex}}_{g,t}$.

The monetary value per unit of energy is denoted by λ, with different labels attached according to which cost or income it signifies. In this section, all λ's are assumed to be non-negative.

In the previous market, a generator has income equal to electricity income plus the revenue from subsidies, and cost equal to operation and maintenance cost. For generators, $\lambda^{\mathrm{O\&M}}_{g,t} \geq 0$. The profit after the previous market is

$$\pi_{g,t}^{\text{base}} = \left(\lambda_t^{\text{el}} + \lambda_{g,t}^{\text{sub}} - \lambda_{g,t}^{\text{O\&M}}\right) P_{g,t}^{\text{base}} \Delta t. \tag{108}$$

After the current market, the output has been adjusted, so the revenue from subsidies and the O&M cost has changed. It is assumed that the electricity income stays firm from the previous market. This corresponds to the case of firm energy tariffs, described in Section 2.3.4 in the deliverable D1.2 [4]. In addition, there is a term associated to the provision of flexibility itself. Thus, the profit after the current market is

$$\pi_{g,t}^{\text{flex}} = \left(\lambda_t^{\text{el}} P_{g,t}^{\text{base}} + \left(\lambda_{g,t}^{\text{sub}} - \lambda_{g,t}^{\text{O\&M}}\right)\left(P_{g,t}^{\text{base}} + P_{g,t}^{\text{flex}}\right) + \lambda_{g,t}^{\text{flex}} P_{g,t}^{\text{flex}}\right) \Delta t. \tag{109}$$

The additional profit (i.e. the difference between the profit after the current market and the profit after the previous market) must be non-negative, or else there would be no point for the generator in participating in the current market:

$$\pi_{g,t}^{\text{flex}} - \pi_{g,t}^{\text{base}} = \left(\lambda_{g,t}^{\text{sub}} + \lambda_{g,t}^{\text{flex}} - \lambda_{g,t}^{\text{O\&M}}\right) P_{g,t}^{\text{flex}} \Delta t \geq 0 \tag{110}$$

$$\Downarrow$$

$$\left(\lambda_{g,t}^{\text{sub}} + \lambda_{g,t}^{\text{flex}} - \lambda_{g,t}^{\text{O\&M}}\right) \operatorname{sign}\left(P_{g,t}^{\text{flex}}\right) \geq 0. \tag{111}$$

Further algebraic manipulation gives

$$\lambda_{g,t}^{\text{flex}} \operatorname{sign}\left(P_{g,t}^{\text{flex}}\right) \geq \left(\lambda_{g,t}^{\text{O\&M}} - \lambda_{g,t}^{\text{sub}}\right) \operatorname{sign}\left(P_{g,t}^{\text{flex}}\right). \tag{112}$$

Let $c_{g,t}^{\text{flex}} = \lambda_{g,t}^{\text{flex}} \operatorname{sign}\left(P_{g,t}^{\text{flex}}\right)$. According to the quantity and price conventions in the deliverable D2.4 [2], this is the price that is expected in the bids submitted to the current market. Then

$$c_{g,t}^{\text{flex}} \geq \left(\lambda_{g,t}^{\text{O\&M}} - \lambda_{g,t}^{\text{sub}}\right) \operatorname{sign}\left(P_{g,t}^{\text{flex}}\right). \tag{113}$$

The flexibility interval of the generator is $\left[P_{g,t}^{\text{flex},-}, P_{g,t}^{\text{flex},+}\right]$. Thus, we get a bid curve as shown in Figure 5.33.

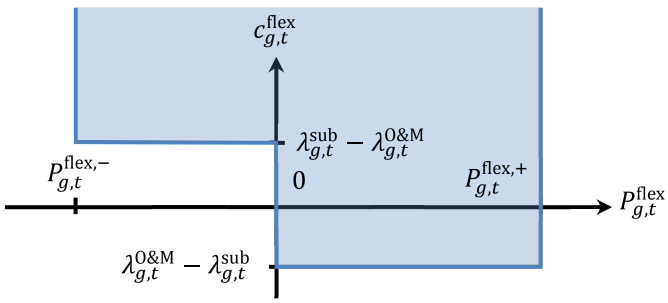


Figure 5.33 Bid curve for a single curtailable generator

Everything on and above the curve (shaded) is acceptable to the generator. The sign of $\lambda_{g,t}^{\text{sub}} - \lambda_{g,t}^{\text{O\&M}}$ can be positive (as shown in the figure) or negative, depending on if the subsidies are large enough to cover the operation and maintenance costs.

5.5.4.2 Flexibility Cost of Load Curtailment

The bid curve for a single load can be calculated in a similar way as for the generator in the previous section. In the previous market, a load has income equal to the revenue from product sales in case of industrial processes, and costs equal to electricity cost plus O&M cost. In this section, all λ's except $\lambda_{d,t}^{\mathrm{O\&M}}$ are assumed to be non-negative in order to be compatible with the unified model presented in the next section. Recall that for a load, $P_{d,t}^{\mathrm{base}} \leq 0$. In the current market, a discomfort cost $c_{d,t}^{\mathrm{dis}}$ is also included, which is a cost that is proportional to the deviation from the power output desired by the load, $P_{d,t}^{\mathrm{d}}$. This is the model for discomfort cost that is mentioned in Section 2.4.8 in the deliverable D1.2 [4]. Assuming that $P_{d,t}^{\mathrm{d}} = P_{d,t}^{\mathrm{base}}$, and using that $P_{d,t}^{\mathrm{out}} = P_{d,t}^{\mathrm{base}} + P_{d,t}^{\mathrm{flex}}$, the discomfort cost becomes

$$c_{d,t}^{\mathrm{dis}} = \lambda_{d,t}^{\mathrm{dis}} \left| P_{d,t}^{\mathrm{out}} - P_{d,t}^{\mathrm{d}} \right| \Delta t = \lambda_{d,t}^{\mathrm{dis}} \left| P_{d,t}^{\mathrm{base}} + P_{d,t}^{\mathrm{flex}} - P_{d,t}^{\mathrm{d}} \right| \Delta t = \lambda_{d,t}^{\mathrm{dis}} \left| P_{d,t}^{\mathrm{flex}} \right| \Delta t. \tag{114}$$

The profit after the previous market is

$$\pi_{d,t}^{\mathrm{base}} = \left(\lambda_t^{\mathrm{el}} - \lambda_{d,t}^{\mathrm{O\&M}} - \lambda_{d,t}^{\mathrm{rev}} \right) P_{d,t}^{\mathrm{base}} \Delta t. \tag{115}$$

The profit after the current market is

$$\begin{aligned} \pi_{d,t}^{\mathrm{flex}} &= \left(\lambda_t^{\mathrm{el}} P_{d,t}^{\mathrm{base}} - \lambda_{d,t}^{\mathrm{rev}} \left(P_{d,t}^{\mathrm{base}} + P_{d,t}^{\mathrm{flex}} \right) + \lambda_{d,t}^{\mathrm{flex}} P_{d,t}^{\mathrm{flex}} \right) \Delta t - c_{d,t}^{\mathrm{dis}} \\ &= \left(\lambda_t^{\mathrm{el}} P_{d,t}^{\mathrm{base}} - \left(\lambda_{d,t}^{\mathrm{O\&M}} + \lambda_{d,t}^{\mathrm{rev}} \right) \left(P_{d,t}^{\mathrm{base}} + P_{d,t}^{\mathrm{flex}} \right) + \lambda_{d,t}^{\mathrm{flex}} P_{d,t}^{\mathrm{flex}} - \lambda_{d,t}^{\mathrm{dis}} \left| P_{d,t}^{\mathrm{flex}} \right| \right) \Delta t. \end{aligned} \tag{116}$$

The additional profit must be non-negative:

$$\pi_{d,t}^{\mathrm{flex}} - \pi_{d,t}^{\mathrm{base}} = \left(\left(\lambda_{d,t}^{\mathrm{flex}} - \lambda_{d,t}^{\mathrm{O\&M}} - \lambda_{d,t}^{\mathrm{rev}} \right) P_{d,t}^{\mathrm{flex}} - \lambda_{d,t}^{\mathrm{dis}} \left| P_{d,t}^{\mathrm{flex}} \right| \right) \Delta t \geq 0, \tag{117}$$

$$\Downarrow$$

$$\left(\lambda_{d,t}^{\mathrm{flex}} - \lambda_{d,t}^{\mathrm{O\&M}} - \lambda_{d,t}^{\mathrm{rev}} \right) \operatorname{sign}\left(P_{d,t}^{\mathrm{flex}} \right) - \lambda_{d,t}^{\mathrm{dis}} \geq 0. \tag{118}$$

Recall that $\mathrm{c}_{\mathrm{d,t}}^{\mathrm{flex}} = \lambda_{\mathrm{d,t}}^{\mathrm{flex}} \operatorname{sign}\left(\mathrm{P}_{\mathrm{d,t}}^{\mathrm{flex}} \right)$. Then

$$c_{d,t}^{\mathrm{flex}} \geq \left(\lambda_{d,t}^{\mathrm{rev}} + \lambda_{d,t}^{\mathrm{O\&M}} \right) \operatorname{sign}\left(P_{d,t}^{\mathrm{flex}} \right) + \lambda_{d,t}^{\mathrm{dis}}. \tag{119}$$

The flexibility interval of the load is $\left[P_{d,t}^{\mathrm{flex},-}, P_{d,t}^{\mathrm{flex},+} \right]$, giving a bid curve as shown in Figure 5.34.

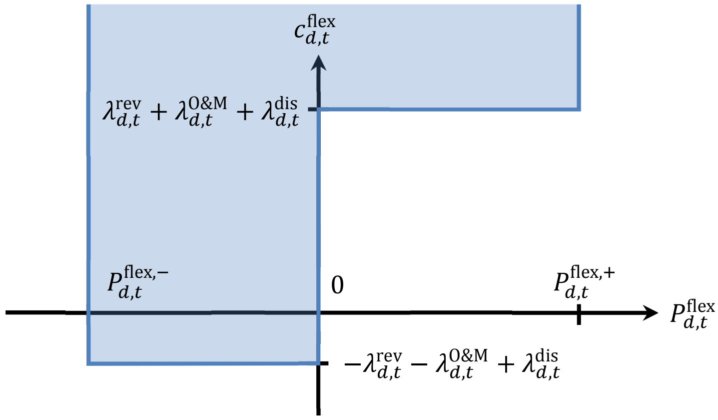


Figure 5.34 Bid curve for a single curtailable load

Everything above the curve (shaded) is acceptable to the load. The size of $\lambda_{d,t}^{\text{rev}}$ determines whether the bid curve enters the lower-left quadrant. If $-\lambda_{d,t}^{\text{O\&M}} + \lambda_{d,t}^{\text{dis}} > \lambda_{d,t}^{\text{rev}}$, then the bid curve would lie entirely in the upper half-plane, meaning that the load would never accept to pay for providing flexibility.

5.5.4.3 Flexibility Cost of Unified Model

As explained in Section 5.5.3.1.3, curtailable generators and curtailable loads can be combined into a single power device model, by using negative values for power output when electricity is consumed by the device, and positive values when it is supplied by the device. Similarly, the flexibility cost can also be combined into downward and upward flexibility costs of the unified model.

Let the number of unified devices be n_R. Then each unified device can be assigned a number $r \in R = \{1,2,\dots,n_R\}$. Two disjoint subsets of R are defined, namely the set of curtailable generators $G \subseteq R$, and the set of curtailable loads $D \subseteq R$. Thus, if $r \in G$, then r is a curtailable generator, and if $r \in D$, then r is a curtailable load. There may be unified devices which fall outside G and D, but which are nevertheless captured by the unified model.

After combining the flexibility cost formulas of curtailable generation and curtailable loads, i.e. (113) and (119), respectively, the flexibility cost of the unified device r becomes

$$c_{r,t}^{\text{flex}} \geq \left(\lambda_{r,t}^{\text{rev}} - \lambda_{r,t}^{\text{sub}} + \lambda_{r,t}^{\text{O\&M}}\right) \operatorname{sign}\left(P_{r,t}^{\text{flex}}\right) + \lambda_{r,t}^{\text{dis}}. \tag{120}$$

For a curtailable generator $r \in G$, it is natural to set the revenue from product sales and the discomfort cost to zero, $\lambda_{r,t}^{\text{rev}} = \lambda_{r,t}^{\text{dis}} = 0$, and $\lambda_{r,t}^{\text{O\&M}} \geq 0$. Conversely, for a curtailable load, it is natural to set the revenue from subsidies to zero, $\lambda_{r,t}^{\text{sub}} = 0$, and $\lambda_{r,t}^{\text{O\&M}} \leq 0$. With these choices, it is evident that curtailable generators and curtailable loads are obtained as special cases for the unified model.

In the notation of Chapter 2, the terms of (120) can be identified as follows:

$$
\begin{aligned}
c_{r,t}^{\text{operational}} &= \lambda_{r,t}^{\text{O\&M}} P_{r,t}^{\text{flex}} \Delta t, \\
c_{r,t}^{\text{discomfort}} &= \lambda_{r,t}^{\text{dis}} \left| P_{r,t}^{\text{flex}} \right| \Delta t, \\
\Delta_{r,t}^{\text{revenue}} &= \left(\lambda_{r,t}^{\text{rev}} - \lambda_{r,t}^{\text{sub}} \right) P_{r,t}^{\text{flex}} \Delta t.
\end{aligned} \tag{121}
$$

5.5.5 Bidding Strategy

The procedure for calculating and aggregating bids is displayed in the flowchart in Figure 5.35.

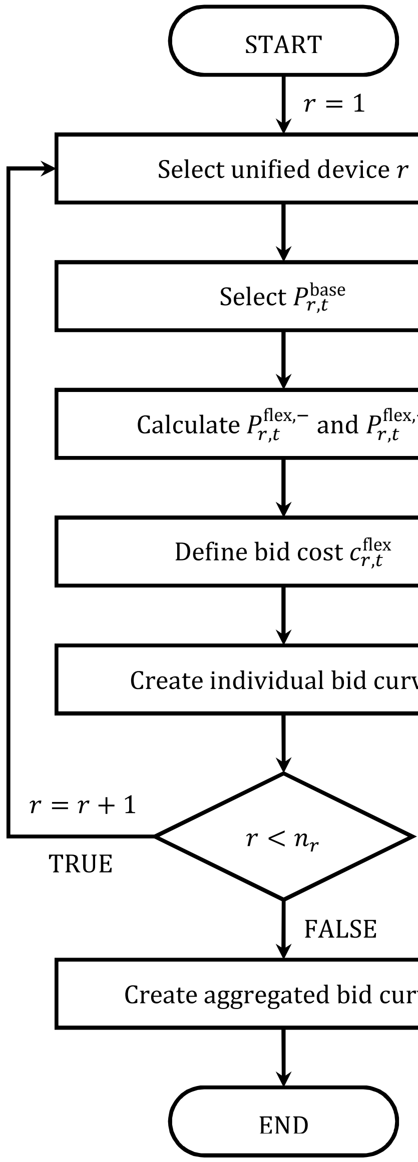


Figure 5.35 Flowchart for calculating aggregated bid curves

Ordinary horizontal summation of the bid functions is used to generate an aggregated bid curve (see [20] and [21]). After the market algorithm has determined prices and power levels, ordinary

disaggregation is applied to obtain $P_{r,t}^{\text{out}}$ for each device. The aggregated bid takes the form of a STEP curtailable Q-bid, as defined in the deliverable D2.4 [2].

Example

In this example, two devices are aggregated, and the aggregated bid function is calculated for a single time step t. Then a price level is decided by the market, and disaggregation is performed. The bid functions of the first device, a generator, and the second device, a load, are shown in Figure 5.36.

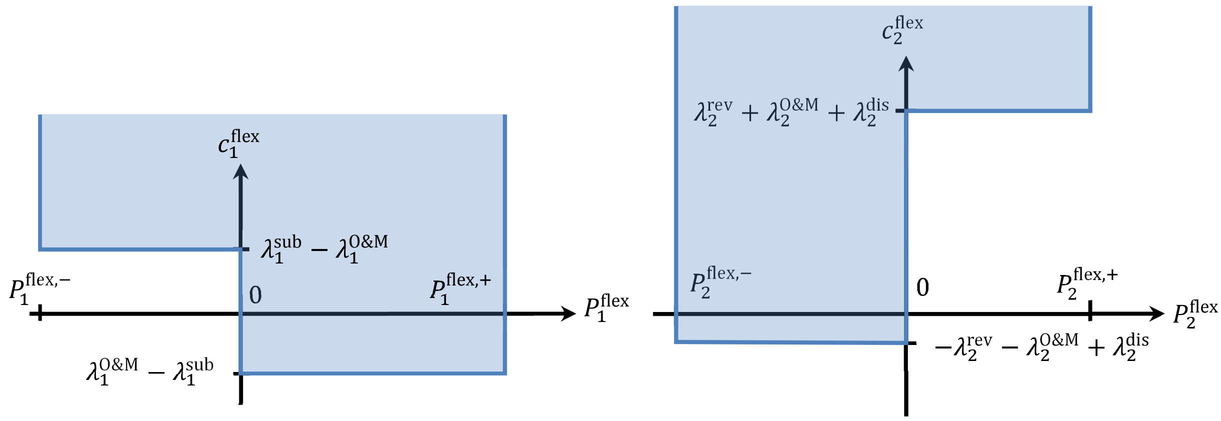


Figure 5.36 Bid functions of a generator (1), and a load (2)

By horizontal summation, the aggregated bid function becomes as shown in Figure 5.37.

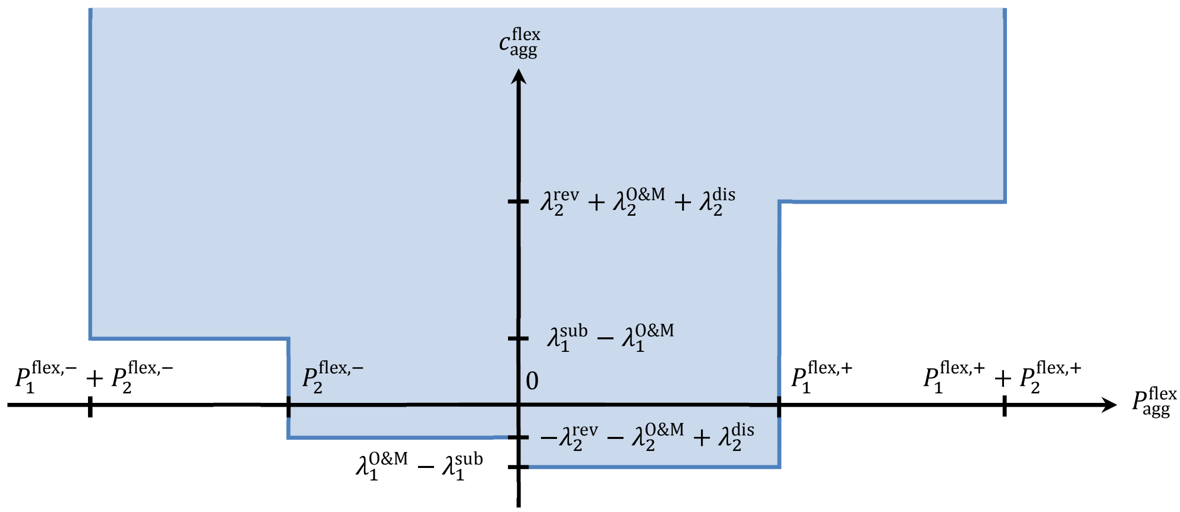


Figure 5.37 Aggregated bid function

Once again, everything above the curve is acceptable (any point inside the shaded area). This curve is submitted to the flexibility market.

As an example of disaggregation, consider the situation where the market decides on a price $c_{\text{agg}}^{\text{flex}} = \lambda_2^{\text{rev}} + \lambda_2^{\text{O\&M}} + \lambda_2^{\text{dis}}$ and flexibility $P_{\text{agg}}^{\text{flex}}$ that satisfies $P_1^{\text{flex},+} < P_{\text{agg}}^{\text{flex}} < P_1^{\text{flex},+} + P_2^{\text{flex},+}$. The generator

will then provide its maximum possible upward flexibility $P_1^{\text{flex},+}$, and the load will provide upward flexibility $P_{\text{agg}}^{\text{flex}} - P_1^{\text{flex},+}$.

6 Disaggregation

When the SmartNet market is cleared, the aggregators are notified whether the submitted bids are accepted or not. Essentially, the accepted bids are the ones with the offering price equal, or lower, to the market clearing price. Hence, the identification of DERs activated for the flexibility purpose is straightforward. Please note that the aggregators are obliged to provide the accepted charge/discharge quantity to the market. An area where the consensus needs to be reached are the STEP curtailable bids (unit, Q and Qt), which have been partially accepted by the market clearing. One approach for solving this issue would be to proportionally allocate the flexibility to all of the devices represented by the partially accepted block. However, partial activation would incur unnecessary costs. Hence, the optimal approach is to activate the least units possible and share the activation revenue.

Three different disaggregation processes are presented in the following sections. The disaggregation process for non-curtailable UNIT bids is presented in Section 6.1, Section 6.2 describes the disaggregation in the case of STEP non-curtailable Q- and Qt-bids, while Section 6.3 explains the disaggregation for STEP curtailable Q- and Qt-bids. It is explained through atomic loads model, TCLs model and EES units models, respectively.

6.1 Atomic Loads

The offer of flexibility $\Delta P_{flex}[t]$ is submitted as a bid to the market with the price $C_{flex} - \tilde{C}$. If the bid is accepted, the s_i^j variables will determine implicitly what is the new selected program, or activation time, for each load, $j_{new}(i)$. These variables make the disaggregation step trivial, since they already indicate which loads need to change their schedules.

If $\tilde{j}(i) = j_{new}(i)$, the selected alternative is the same, and load i does not participate in the bid, keeping the same scheduled alternative.

There is nothing to be done concerning a load i, and the next actions are only related to a smaller set of active loads which were requested to change their activation time, in order to deliver the flexibility proposed by an accepted bid. From this smaller group of active loads, the aggregator must deal first with the most urgent ones. The urgent loads are those, which are involved directly in the next time slot.

There are active loads that are requested to anticipate their activation in the next time slot. These devices need to be notified as soon as possible in order to confirm that they are able to advance their activation as expected. These early activations will increase the power consumption for the next time slot.

Some active loads face the opposite situation. They were scheduled to activate in the next time slot, but the accepted bid will require them to postpone their activation. Those loads also need to confirm that they can still delay their start[22]. This will decrease the power consumption in relation to the baseline.

There are other updates related to remaining active loads that are not urgent. They will shape the rebound effects for the future time steps, or reduce the potential imbalances expected by the aggregator.

These reschedules can be seen as tentative. Those loads are notified of their new alternative schedule, the imbalances are updated, assuming the bid will be delivered with the agreed profile.

The first column in Figure 6.1 displays the flexibility that would be released by the urgent loads only – the only ones responsible for producing a positive peak on the next time slot.

The second column in Figure 6.1 illustrates the tentative rescheduling of loads that are notified of future time steps' changes. Together they result in a release of flexibility that cancels out the fluctuations generated from the rescheduling of the urgent active loads.

Finally, the flexibility offered to the market is in the third column in Figure 6.1, combining all active loads together. Notice that this combination is produced in order to keep the rebound limited.

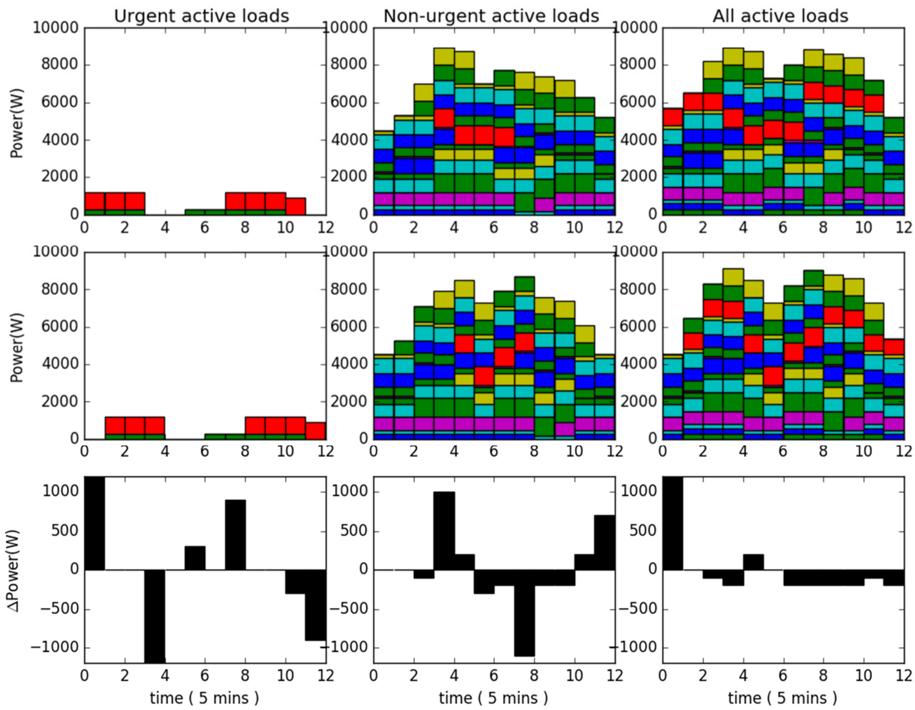


Figure 6.1 Flexibility offered by urgent and non-urgent active loads

[22] Advancing and postponing atomic load activation at a short notice can be seen as the essence of this type of flexibility.

6.2 Thermostatically Controlled Loads

Once the aggregator receives the information about the accepted bids, it needs to transform those market results into individual set points to be delivered to the TCLs. This process is called disaggregation and is a fundamental step for the activation of flexibility.

In case of the single step bid, Q-bid, creation model, the disaggregation is straightforward since the aggregator knows at bid creation time the mapping between individual control set points and power vs. price steps. Therefore, once the market accepts the flexibility volumes, there is a direct link with the individual set points to be applied.

Following the same example as the one presented in Section 5.3.2.1.1.2, Figure 6.2 shows how every step in the aggregated bid corresponds to a certain TCL device and control set point.

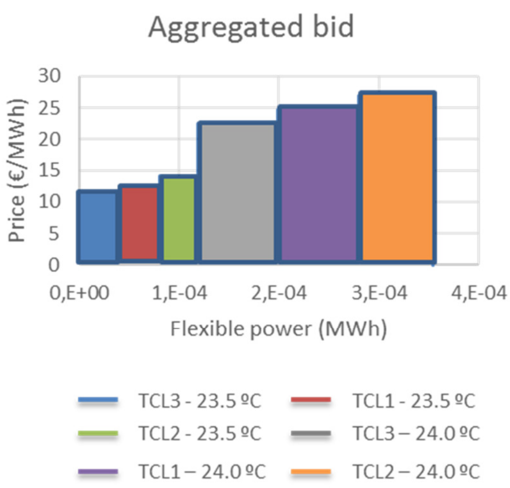


Figure 6.2 Disaggregation example

Note that the bids are submitted with a "non-curtailable" constraint, such that each device's flexibility is accepted completely or not accepted at all.

In a similar way as with the single-step bid creation model above, the disaggregation for multi-step bids, Qt-bids, based on the predefined control set points, is also straightforward. At the time of bid creation, the aggregator already knows the temperature set point that corresponds to each power profile. So when the market informs the aggregator about the selected profile (if any), the aggregator just needs to send the corresponding temperature set point to all of the TCLs is the aggregation set.

6.3 Electric Energy Storage Units

EES units disaggregation model is a cost minimizing optimization problem, whereas the main objective of the EES units aggregator is to supply the accepted charge/discharge quantity with the lowest possible cost. The disaggregation algorithm for an EES units aggregator, participating in the SmartNet balancing market, is presented below.

6.3.1 Nomenclature

A. Parameters

$\lambda_t^{cleared}$	Cleared SmartNet market price
Θ_k^{maxdch}	Maximum rate of reactive power discharge for an EES
Θ_k^{maxch}	Maximum rate of reactive power charge for an EES
$\alpha_1 \dots \alpha_4$	Scalars to weight the shortage or excess of power in the objective function

B. Variables

$p_{k,t}^{BchAcp}$	Balancing market accepted charge level for k^{th} EES
$p_{k,t}^{BdchAcp}$	Balancing market accepted discharge level for k^{th} EES
$AP_t^{BdchAcp}$	Aggregated accepted discharge volume per time step t
AP_t^{BchAcp}	Aggregated accepted charge volume per time step t
p_t^{sh}	Shortage of active power per time step t
p_t^{ex}	Excess of active power per time step t
$\theta_{k,t}^{BchAcp}$	Balancing market accepted charge level for reactive power of k^{th} EES
$\theta_{k,t}^{BdchAcp}$	Balancing market accepted discharge level for reactive power of k^{th} EES
θ_t^{sh}	Shortage of reactive power per time step t
θ_t^{ex}	Excess of reactive power per time step t
$A\Theta_t^{BdchAcp}$	Aggregated accepted discharge volume for reactive power per time step t
$A\Theta_t^{BchAcp}$	Aggregated accepted charge volume for reactive power per time step t

6.3.2 Objective Function

The objective function stated in (122) aims at minimizing the aggregator's cost while providing accepted active and reactive power in the SmartNet market.

$$\text{Minimize} \sum_{t=1}^{T}\sum_{k=1}^{K}\left[\left(c\,\frac{p_{k,t}^{BdchAcp}}{\eta_k^{dch}}\Delta t + \left|\frac{\mu_k}{100}\right|\frac{c_k^{cap}}{E_k^{max}}p_{k,t}^{BdchAcp}\Delta t\right) + \left(\lambda_t^{cleared}\eta_k^{ch}p_{k,t}^{BchAcp}\Delta t + \left|\frac{\mu_k}{100}\right|\frac{c_k^{cap}}{E_k^{max}}p_{k,t}^{BchAcp}\Delta t\right)\right] + \sum_{t=1}^{T}(\alpha_1 p_t^{sh} + \alpha_2\theta_t^{sh} + \alpha_3 p_t^{ex} + \alpha_4\theta_t^{ex}) \tag{122}$$

The first line of the equation (122) describes the EES aggregator's cost related to discharging. Please note that the total discharge cost includes commitment and degradation costs. The second line in (122) describes the EES aggregator's cost while charging. In a similar way, the total charging cost consists of energy bought from the SmartNet market with the cleared market price and the battery degradation cost. Finally, the third line in (122) addresses the cost for those hours when the aggregator has either shortage or excess of active and reactive power.

6.3.3 Constraints

The equations (123) and (124) ensure that all devices together provide discharge/charge active power quantity committed in the SmartNet market. Auxiliary variables p_t^{sh} and p_t^{ex} are added to equations (123) and (124) respectively to address last minute unexpected events causing potential imbalances (for example unavailability of several EVs) and resulting additional cost for the aggregator.

$$\sum_k p_{k,t}^{BdchAcp} + p_t^{sh} = AP_t^{BdchAcp} \tag{123}$$

$$\sum_k p_{k,t}^{BchAcp} + p_t^{ex} = AP_t^{BchAcp} \tag{124}$$

In the similar way, the equations (125) and (126) make sure that the reactive power quantity, accepted by the SmartNet market, will be supplied smoothly.

$$\sum_k \theta_{k,t}^{BdchAcp} + \theta_t^{sh} = A\Theta_t^{BdchAcp} \tag{125}$$

$$\sum_k \theta_{k,t}^{BchAcp} + \theta_t^{ex} = A\Theta_t^{BchAcp} \tag{126}$$

The reactive power charge/discharge bounds are set with the help of the constraints (127) and (128).

$$0 \le \theta_{k,t}^{BdchAcp} \le A_{k,t}\,\Theta_{k,t}^{maxdch} \tag{127}$$

$$0 \le \theta_{k,t}^{BchAcp} \le A_{k,t}\,\Theta_{k,t}^{maxch} \tag{128}$$

The constraints (129)–(135) have been explained in the EES unit aggregation under section 5.4.2.3.

$$SoC_{k,t}^{B} = SoC_{k,t-1}^{B} + \left[p_{k,t}^{ch}\,\Delta t \eta_k^{ch} - \frac{p_{k,t}^{dch}}{\eta_k^{dch}}\Delta t + p_{k,t}^{BchAcp}\Delta t\eta_k^{ch} - \frac{p_{k,t}^{BdchAcp}}{\eta_k^{dch}}\Delta t \right] A_{k,t} - D_k \Delta t \eta_k^{dr}\left(1 - A_{k,t}\right) \tag{129}$$

$$\gamma_k^{min} E_k^{max} \leq SoC_{k,t}^{B} \leq \gamma_k^{max} E_k^{max} \tag{130}$$

$$A_{k,t} P_k^{mindch} \leq p_{k,t}^{BdchAcp} \leq (P_k^{maxdch} - p_{k,t}^{dch} + p_k^{ch}) A_{k,t} \tag{131}$$

$$A_{k,t} P_k^{minch} \leq p_{k,t}^{BchAcp} \leq (P_k^{maxch} - p_{k,t}^{ch} + p_k^{dch}) A_{k,t} \tag{132}$$

$$-R_k^{maxRDdch} \leq \left(p_k^{dch} + p_{k,t}^{BdchAcp}\right) - \left(p_{k,t-1}^{dch} + p_{k,t-1}^{BdchAcp}\right) \leq R_k^{maxRUdch} \tag{133}$$

$$-R_k^{maxRDch} \leq \left(p_k^{ch} + p_{k,t}^{BchAcp}\right) - \left(p_{k,t-1}^{ch} + p_{k,t-1}^{BchAcp}\right) \leq R_k^{maxRUch} \tag{134}$$

$$SoC_{k,T}^{B} \geq SoC_{k,T}^{Bend} \tag{135}$$

6.3.4 The EES Units Disaggregation Optimization Problem

The EES aggregator solves the problem stated below, using LP, in order to disaggregate the active/reactive power accepted by the SmartNet market.

$$\text{Maximize} \sum_{t=1}^{T_m}\sum_{k=1}^{K}\left[\left(c\,\frac{p_{k,t}^{BdchAcp}}{\eta_k^{dch}}\Delta t + \left|\frac{\mu_k}{100}\right|\frac{c_k^{cap}}{E_k^{max}} p_{k,t}^{BdchAcp}\Delta t\right) + \left(\lambda_t^{cleared}\eta_k^{ch} p_{k,t}^{BchAcp}\Delta t + \left|\frac{\mu_k}{100}\right|\frac{c_k^{cap}}{E_k^{max}} p_{k,t}^{BchAcp}\Delta t\right)\right] + \sum_{t=1}^{T}(\alpha_1 p_t^{sh} + \alpha_2 \theta_t^{sh} + \alpha_3 p_t^{ex} + \alpha_4 \theta_t^{ex}) \tag{136}$$

subject to (123)-(135).

7 Conclusion

Due to growing penetration of variable RES, primarily the integration of solar and wind power generation on a large scale, power systems' flexibility has become a fundamental necessity. It is argued by the SmartNet project that, with a supporting distribution level ICT infrastructure, the flexibility needs can be met, to a certain extent, by the DERs. The inter-temporal ramping constraints of certain types of DERs are well suited for the short-term distribution level flexibility market, being developed within the project. The EES devices, and certain types of loads, can respond almost instantaneously to the flexibility needs.

In the SmartNet AS market design it is the role of the aggregator to make the flexibility from diverse DERs suitable for participation in this novel AS market, which will help meet the system's flexibility requirements. In principle, it is possible to define a hierarchy of aggregation levels, where the initial level is the aggregation-type-specific category, a level above is aggregation per node, and "super-aggregation" could be done at the transmission level – distribution level interface. However, in this deliverable five type-specific-aggregations are chosen, since the same aggregator can issue different types of bids. This is a step towards DERs flexibility, source specific, AS retail market. Hence, the scope of the document is limited to the initial level of aggregation.

The following conclusions can be drawn from this document:

- The flexibility cost framework of aggregated DERs was presented in Chapter 2. The flexibility cost depends on the type of DERs being aggregated and consists of different components: discomfort cost, operational cost, revenue change, and indirect cost. The indirect cost can have different values depending on the rebound/payback effect. While it is zero if there is no rebound effect, in case when the flexible aggregated asset has a rebound effect, the indirect cost depends on the time when this effect occurs, i.e. inside or outside of the time horizon of the market.
- Market arbitrage is described in Chapter 3, in a form of an additional, i.e. fifth, flexibility cost component named market discomfort cost. In essence, MDC works as an opportunity cost, representing the additional revenue of a near-future activation. MDC makes the aggregator indifferent between an immediate activation and the one in the future at a (potentially) better profit. This new, artificial, cost variable is meant to refrain the aggregator from jumping too fast at the first opportunity, disregarding the future value of a limited number of available activations. There are also reasons, other than MDC, which can lead to bidding higher than the marginal operational cost. Such costs include, for instance, investments into the complex aggregation systems. Therefore it is important to set the bid prices such that the aggregators can recover their investments. The analysis of the additional costs is, however, rather complex, and out of the scope of the intended purpose of this deliverable.

- Four aggregation approaches were reviewed in Chapter 4. These are physical (bottom-up), traces, justified approximation (hybrid) and data-driven aggregation. While it is assumed that the aggregator knows all parameters of each individual device in the physical approach and load profiles and the cost associated to each of the profiles in the traces approach, justified approximation approach represents the entire population of aggregated devices by using a single, or a limited number of virtual devices. The advantages of all of these approaches is straightforward disaggregation. Due to required increased amount of input data, as well as a disaggregation model, the data-driven approach is not used in the SmartNet project.
- Five aggregation models were developed in Chapter 5. They are obtained by clustering eight different DER categories introduced in the deliverable D1.2 [4], based on the modelling similarities. Each model defines the quantity of the active power flexibility submitted to the market, as well as the associated flexibility cost and the bidding strategy. The aggregation models are predominantly based on the bottom-up aggregation approach. This approach is used for the aggregation of CHP Units, TCLs, EES Units and Curtailable Generation and Curtailable Loads. The bottom-up approach, otherwise cumbersome when considering the transmission level, was selected as the preferred option due to the lower number of devices, which are being aggregated into each MV node. However, due to a specific nature of some of the DERs, traces and justified approximation (hybrid) approaches are also used in the project. Given the physical characteristics of atomic loads, they are aggregated by using the traces aggregation approach. The justified approximation approach is used as the alternative approach for the aggregation of TCLs, given the fact it reduces the high number of individual devices and avoids the large number of input parameters.
- Disaggregation was described in Chapter 6. The disaggregation process depends on the type of the aggregation approach used for devices' aggregation, as well as the type of the bids submitted to the market.
- Development of pseudo-algorithms which render the aggregation models implementation almost straightforward.

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9 Appendix A: Updates done since the preliminary report

The following lists the modifications introduced with respect to the preliminary report (D2.3) due to the modifications/upgrades introduced into the aggregation models as a consequence of the support given to the simulation platform build up in WP4.

The scope of the document, in Chapter 1, has been reworked, in order to include the literature review of the two projects in which DERs' aggregation has previously been considered, and in order to compare the aggregation implemented in SmartNet to the aggregation done previously in these projects. Furthermore, the advantages, as well as the disadvantages, of the SmartNet aggregation approach, in comparison to one of the referenced projects, have been highlighted.

An important update, since the preliminary report release, is the implementation of market arbitrage. It is represented in a form of an artificial cost, named market discomfort cost. In essence, MDC works as an opportunity cost, representing the additional revenue of a near-future activation. MDC makes the aggregator indifferent between an immediate activation and the one taking place in the future, at a (potentially) better profit. This new cost variable is meant to refrain the aggregator from jumping too fast at the first opportunity, disregarding the future value of a limited number of activations available. Hence, MDC refrains them from offering their flexibility at purely technical cost, and introduces a risk-premium or psychological factor that increases the required return from activation, thereby generating the right economic incentive to the aggregator and ultimately DERs. Incorporating MDC into the flexibility cost reduces the probability of an immediate activation. However, this does not mean that the aggregator will reject activations, only that it will, at least, require making profit in order to be satisfied.

In the deliverable D2.3, each aggregation model uses different units of measurement for the same physical values. These units, as well as the symbology, are now standardized in this deliverable, i.e. D2.1. This means that while in the deliverable D2.3 a physical value was represented by two different symbols, or the same symbol had different representations depending on the deliverable section, this has now been corrected in this manuscript. The same can be stated for the units of measurements, where all of the aggregation models use the same unit of measurement for the same physical value. The bulk of this work was carried out in Chapter 5. The power flexibility bids cost has been changed from *euro* to *euro per unit of energy* in the figures and the text of the deliverable. The total cost remained in *euro*, however.

Furthermore, the aggregation models have been reviewed in this final report of Task 2.2, based on the feedback received from WP4. Updates done to the atomic loads aggregation model:

- Responsiveness of a cluster of appliances to a price indication has been added to an existing aggregation model (see section 5.1.3.2.3), and a new reference has been inserted.

Updates done to TCL aggregation model are:

- Integral constraint for the multi-period bids has been replaced by "Accept-All-Time-Steps-Or-None" constraint, where the power profile offered includes both the flexibility period corresponding to the application of the control set-point, as well as the rebound period caused by it (see section 5.3.1.2.2). The example has been updated accordingly.
- A new section including the calculation of the reactive power for the bids has been added (see section 5.3.2.1.1.4).
- An approach to calculate the comfort sensitivity (δ) for the calculation of the discomfort cost has been proposed. This parameter measures the economic benefit to be obtained for a unit of temperature deviation (see section 5.3.1.2.3).

Updates done to EES units aggregation model:

- This aggregation model has gone through a considerable revision. Small PHES have been incorporated in the aggregation model. It is now set up as a LP optimization problem, with the objective of aggregator's profit maximization. Also new references have been added to the section.
- In order to benefit from the information being released over time, rolling planning has been incorporated (see section 5.4.2.4).
- A pseudo-algorithm, which renders the aggregation model implementation straightforward, has been defined and added (see section 5.4.3).
- A new section considering the reactive power capability of EES units has been included (see section 5.4.3.1).
- EES units disaggregation model is set up as a LP optimization problem, with the objective of aggregator's cost minimization (see section 6.3).

10 Appendix B: Advisory Board Meeting Comments

Comment 1

"Aggregator role

Text of the aggregator role to act on behalf of service providers, I am not sure to agree. Aggregator is in parallel to service providers, ancillary service providers. But it acts as intermediary between flexibility nodes, i.e. providers of flexibility services (home residential, commercial, industrial) and market, with very clear role of aggregation of capacity and presenting it to different electricity markets."

Response 1

In response to this comment, the following figure and the supporting text has been added to Section 1.1:

"

Figure 1.1 Illustration of aggregation, bidding and disaggregation processes

An aggregator acts as an intermediary between the flexibility service providers, and the market, with a very clear role of aggregation[23] of the available flexibility volume. An aggregator is also in charge of the disaggregation, also referred to as allocation, or resources' activation, after a successful aggregation and market clearing have taken place. In terms of the power system's operation, disaggregation is equivalent to the generation economic dispatch, plus unit (de)commitment."

Comment 2

"The bottom-up approach was selected as the preferred option due to the lower number of devices which are being aggregated at each MV node." Where is reference to LV aggregation, since a vast majority of todays DR/DG is located there. Or make a text change, e.g. "... aggregated into each MV node.", which hints to summing of DR/DG at LV into MV, e.g. at transformer level."

Response 2

In response to this comment the following text in Chapter 4, has been changed accordingly:

[23] The term aggregation implies horizontal summation of the flexibility volume at rising cost.

“The bottom-up approach was selected as the preferred option due to the lower number of devices, which are being aggregated into each MV node. The number of devices is higher when aggregating into the transmission level node, making the bottom-up approach cumbersome. The aggregation is done into each MV distribution level node separately, as shown in the example of “Node B” in Figure 4.1.”