Platone

PLATFORM FOR OPERATION OF DISTRIBUTION NETWORKS

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PLATform for Operation of distribution NEtworks

D4.3 v1.0

Algorithm for ancillary services

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Abstract

Deliverable 4.3: “Algorithm for ancillary services” presents the framework methodology and the software tool developed for the coordination of Distributed Energy Resources (DERs) in order to enable them to provide ancillary services to Transmission System Operators (TSOs), without a much less significant impact on distribution networks. The tool is destined for Distribution System Operators. The methodology analysed in this deliverable presents a method to design Real-Time (RT) Distribution Use of System (DUoS) tariffs through a bilevel optimization model which captures the interaction between a DSO and prosumers with DERs. The method expands on and is complementary to the Day-Ahead (DA) DUoS tariffs design method of D4.4. As in D4.4, the methodology considers a detailed representation of the power flow constraints, different levels of temporal and spatial granularity in the designed tariffs, as well as discrete tariff levels for preserving intelligibility. The efficacy of the method is demonstrated by using case studies for different operating conditions.

Keyword list

Bilevel optimization, balancing market, clustering, Distributed Energy Resources, Distribution Use-of-System tariffs, flexibility, Real-Time pricing

Disclaimer

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Executive Summary

"Innovation for the customers, innovation for the grid" is the vision of project Platone - Platform for Operation of distribution Networks. Within the H2020 programme "A single, smart European electricity grid", Platone addresses the topic "Flexibility and retail market options for the distribution grid". Modern power grids are moving away from centralised, infrastructure-heavy transmission system operators (TSOs) towards distribution system operators (DSOs) that are flexible and more capable of managing diverse renewable energy sources. DSOs require new ways of managing the increased number of producers, end users and more volatile power distribution systems of the future. Platone is using blockchain technology to build the Platone Open Framework to meet the needs of modern DSO power systems, including data management. The Platone Open Framework aims to create an open, flexible and secure system that enables distribution grid flexibility/congestion management mechanisms, through innovative energy market models involving all the possible actors at many levels (DSOs, TSOs, customers, aggregators). It is an open-source framework based on blockchain technology that enables a secure and shared data management system, allows standard and flexible integration of external solutions (e.g. legacy solutions), and is open to integration of external services through standardized open application program interfaces (APIs). It is built with existing regulations in mind and will allow small power producers to be easily certified so that they can sell excess energy back to the grid. The Platone Open Framework will also incorporate an open-market system to link with traditional TSOs. The Platone Open Framework will be tested in three European field trials and within the Canadian Distributed Energy Management Initiative (DEMI)."

Work Package 4 (WP4) includes the activities of the Greek demo at the Mesogia area of Attica. One of the key elements of the Greek demo is the development of algorithms for control of Distributed Energy Resources (DERs). As explored in the deliverable that preceded this one (D4.4), there are challenges that relate to respecting distribution network constraints in the presence of non-dispatchable or variable Distributed Energy Resources (DERs). Moreover, it was proved that DUoS tariff schemes could reflect the possibility to manage DERs at a shorter time scale, while at the same time retaining traditional DUoS tariff traits, such as DSO cost recovery through tariff revenue and simplicity/intelligibility for the end-user. However, while a method of ex-ante Day-Ahead (DA) tariffs could capture most of the flexibility potential of DERs, additional gains can be extracted by expanding this framework with a closer to Real-Time additional component. The resulting RT DUoS tariffs complement the DA tariffs of the previous deliverable (D4.4) and add efficiency, in terms of operational cost savings, to the overall framework.

As with the DA tariffs, the proposed tool relies on a Stackelberg game formulation that forms a bilevel optimisation type mathematical model. There is a leader (upper level), the DSO, and a follower (lower level), the aggregators/prosumers. The interaction of the two gives two optimisation problems which influence each other (hence bilevel optimisation). The upper level consists of the DSO objective, which is the minimisation of operational costs, and the constraints, which are the power flow constraints, tariff format constraints and (optionally) revenue recovery of costs. The lower level consists of the prosumer objective, which is the minimisation of costs and discomfort, and the constraints include DER constraints from DERs that the prosumer operates. The model cannot be solved in its initial format; hence, it is transformed into its equivalent Mathematical Program with Equilibrium Constraints (MPEC) by making use of the Karush-Kuhn-Tucker (KKT) conditions of the lower level which are added as constraints to the upper level. The new model is then linearised in the case of non-linear and bilinear terms and it, finally, becomes a Mixed-Integer Quadratically constrained Program (MIQP) which can be solved reliably with commercial solvers. The RT tariffs that are created, just as the DA tariffs, are not continuous variables but only a few distinct levels are used to retain intelligibility for the end-user.

The DA tariff method is executed once every year (close to the change of year) using historical data analysis and clustering to design the ex-ante tariffs. The few tariff patterns that are designed are communicated to all stakeholders and each day, the tariff pattern for the next day is chosen among the designed ones. The choice is based on the forecast of which day-type the next day belongs to. When the next day starts, the DSO monitors the situation. If a TSO request for balancing energy from DERs, located in the distribution network, arrives, the DSO acts by executing the RT DUoS tariffs design method. The method designs new tariff components, to be added to the DA tariffs, for the remainder of the day. The goal is for the DSO to communicate to the end-users the new value of the distribution network due to the updated conditions in the wholesale market.

As with the DA tariff method, a design and validation framework was created to test the methodology. The efficacy of the method is compared to the case where it is not deployed. The results include a detailed comparison for a single instance of method activation and year-long aggregated results. All case studies clearly demonstrate the significant operational cost saving the method can achieve.

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1 Introduction

The project "PLATform for Operation of distribution Networks – Platone" aims to develop an architecture for testing and implementing a data acquisition system based on a two-layer Blockchain approach: an "Access Layer" to connect customers to the Distribution System Operator (DSO) and a "Service Layer" to link customers and DSO to the Flexibility Market environment (Market Place, Aggregators, …). The two layers are linked by a Shared Customer Database, containing all the data certified by Blockchain and made available to all the relevant stakeholders of the two layers. This Platone Open Framework architecture allows a greater stakeholder involvement and enables an efficient and smart network management. The tools used for this purpose will be based on platforms able to receive data from different sources, such as weather forecasting systems or distributed smart devices spread all over the urban area. These platforms, by talking to each other and exchanging data, will allow collecting and elaborating information useful for DSOs, transmission system operators (TSOs), Market, customers and aggregators. In particular, the DSOs will invest in a standard, open, non-discriminatory, blockchain-based, economic dispute settlement infrastructure, to give to both the customers and to the aggregator the possibility to more easily become flexibility market players. This solution will allow the DSO to acquire a new role as a market enabler for end users and a smarter observer of the distribution network. By defining this innovative two-layer architecture, Platone strongly contributes to aims at removing technical and economic barriers to the achievement of a carbon-free society by 2050 [1], creating the ecosystem for new market mechanisms for a rapid roll out among DSOs and for a large involvement of customers in the active management of grids and in the flexibility markets. The Platone platform will be tested in three European trials (Greece, Germany and Italy) and within the Distributed Energy Management Initiative (DEMI) in Canada. The Platone consortium aims to go for a commercial exploitation of the results after the project is finished. Within the H2020 programme "A single, smart European electricity grid" Platone addresses the topic "Flexibility and retail market options for the distribution grid".

1.1 Task 4.3

In Task 4.3 "Ancillary services to the TSO provided by the DSO", an algorithm and the corresponding tool is developed for providing ancillary services using distribution network flexibility. In this task, a mathematical model is developed that describes the problem of providing ancillary services using flexibility of the customer load in order to provide short-term (close to Real-Time) services, such balancing energy or frequency reserves for the power system. This means that the flexible loads will be aggregated to participate in the balancing market (load following) and/or provide reserve in a cost optimal manner. The efficacy of the algorithm will be tested using simulations.

1.2 Objectives of the Work Reported in this Deliverable

The objective of this Deliverable is to present the work developed in subtask 4.3.1. This includes the design, development and extensive validation of the algorithm for ancillary services. The algorithm is based on the design of variable Distribution Use-of-System (DUoS) tariffs and complements the algorithm for DER control of Deliverable 4.4 [2].

1.3 Outline of the Deliverable

Chapter 2 provides the required background. Chapter 3 describes the mathematical model. Chapter 4 illustrates the testing framework and modules, the input data and the development platform while Chapter 5 presents and analyses the results from the case studies. Finally, Chapter 6 provides the conclusion.

1.4 How to Read this Document

Some background on DER flexibility issues and different methodologies is beneficial for the understanding of the underlying motivation of DUoS tariffs vs locational marginal pricing. Relevant background to mathematical optimisation and bilevel models could be useful for comprehension of the model. Most importantly, however, this report should be read after D4.4 [2], as it expands on and complements the method of D4.4.

The report is, also, linked to D4.1 [3], which provides a detailed description of the Greek demo, its Use Cases and the related KPIs, and D1.2 [4], which elaborates on calculation methodology, data collection and baseline details for all Demos' KPIs and defines Project KPIs.

2 Background

This chapter provides some necessary background for the presented methodology. First of all, the time frame market context in which the method is envisioned is presented, and its potential usage highlighted. Then, the basic idea of the RT DUoS tariffs is discussed and its relation to the ex-ante DA DUoS tariffs is explained and justified.

2.1 What "real-time" means in the context of D4.3?

The term real-time (often abbreviated as RT) in this document has a very specific meaning. It is defined in the context of electricity markets, i.e., the Target Model. In that context of short-term markets within the Target Model, there are, firstly, the Day-Ahead (DA) auction-type market (see also Figure 1) that is cleared around noon of the previous day (minimum 12 hours before the day of interest starts). Then, there is the Intra-Day (ID) market(s), which can consist of bilateral agreements that take place up until 15 minutes before the hour of interest, and/or DA-style auction(s) that aim at correcting imbalances that become more likely after the DA clearing.

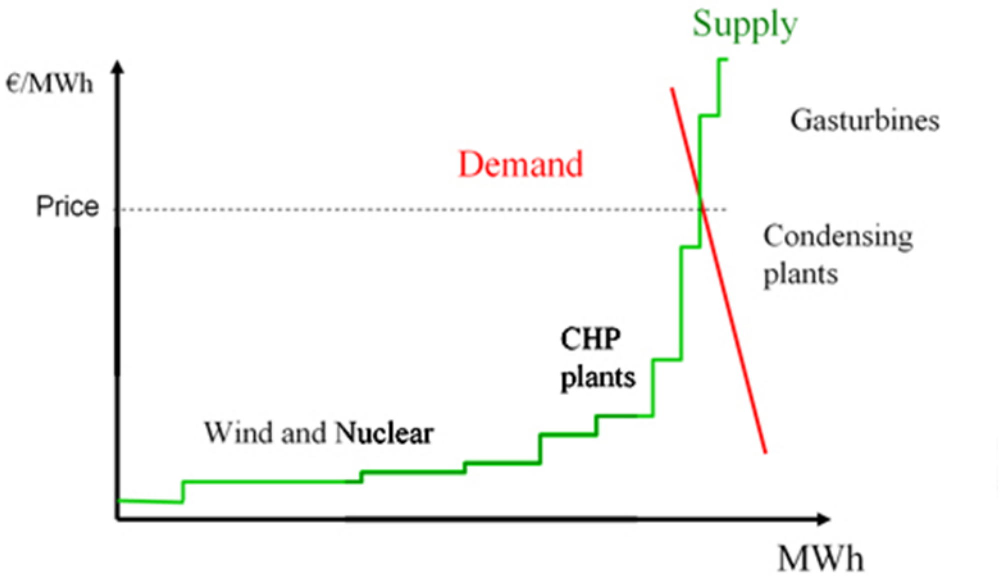

Figure 1: Supply and demand curve for the NordPool power exchange, source [5]

The Regulating/Balancing market frame follows. The Regulating power market is taking place just before or during the time period of interest (can be 15min, 30min, or an hour) and the TSO is the sole buyer (monopsony) in that market, trying to keep the power balance in the system neutral. Almost all entities can be sellers. The balancing market settles a-posteriori all imbalances not accounted for in the DA and ID time scales that manifested during operation. Therefore, one can clearly see that the two markets are connected, and often are discussed at the same time. Additionally, to the Regulating market, other, more urgent energy products can include Frequency Containment and Frequency Restoration Reserves (FCR, FRR). All of the above, are included in the term Real-Time we use in this deliverable. This means that the proposed scheme, with minor changes, can be applied in the context of the Regulating Market or for Reserves. However, for simplicity, we consider only the Regulating/Balancing market context, here. Therefore, Real-Time (RT) and RT DUoS tariffs refer to the Regulating/Balancing market time frame.

2.2 RT DUoS Tariffs

In this framework we envisioned that the TSO is buying power (energy in practice) from an aggregator (or prosumer) located in the distribution network. This aggregator has offered his flexibility as an energy product for a certain price. Once, the TSO announces to the DSO that a price is offered per kWh of provided energy, the DSO needs a way to influence the aggregator's response in order to reduce distribution network operation costs, without directly interfering with each aggregator's DER setpoints.

Similarly, to D4.4 [2], we argue that a useful and practical way to do so is to communicate the value of network usage per kWh, as it forms in these new conditions that were triggered, via Distribution network Use-of-System Tariffs (DUoS) that have Real-Time (RT) applicability.

The derivation of the RT DUoS tariffs is analogous to that of the ex-ante DA DUoS tariffs of D4.4 [2]. Analogous means that the same idea is applied on the new problem of **real-time pricing of the usage of distribution networks**. However, the requirements of the problem are different. The scope of the problem is not a year. The tariffs are not scheduled to be designed before the start of each year and each tariff pattern does not necessarily cover an entire day. Instead, the tariffs are designed on the spot (hence real-time), upon request, and **the scope is the next operational time period and the rest of the day**, i.e., we have a shrinking horizon**.** Therefore, the RT tariff design problem has one less dimension, that of day-types.

Moreover, **the revenue adequacy constraint is optional**. This means that the DSO is not restricted to recover any operational costs via the tariffs. This is because this constraint can be very restrictive and prevent the DSO from finding the best solution in terms of social welfare. In addition, one can argue that the bulk of operational costs is being recovered from the ex-ante DUoS tariffs of the previous deliverable.

Apart from the aforementioned differences, the most important elements of the methodology in D4.4 are present here, too. There is a detailed model of the network, the tariffs have temporal and locational variation in addition to discrete levels. **The RT tariffs are designed as an addition to the DA tariffs** with larger ranges of variation to reflect that, balancing prices reach more often higher levels.

3 Problem formulation

3.1 Model Assumptions

Before discussing the mathematical formulation, it is important to discuss the main assumptions. These assumptions are not simplifications but describe key aspects of the proposed methodology that are also reflected in the formulation. These assumptions are with regards to the problem structure, the tariff types, the way DERs are represented by prosumers and the network model used.

Problem structure: The examined RT DUoS tariff design problem is modelled as a Stackelberg game using bilevel optimization. The upper level expresses the decision-making problem of the DSO who designs tariffs in order to maximize the operating efficiency of the distribution network. The latter is measured by the total cost of demand curtailment and generation curtailment actions which the DSO needs to resort to in order to preserve the security of the network. Curtailment costs can be considered as an approximation of prospective investment costs induced by network congestion effects. The lower level expresses the decision-making problem of prosumers who optimize their demand response actions in response to the RT DUoS tariffs devised by the DSO as well as the energy and balancing tariffs offered by their supplier. Considering that the focus of this method lies in the design of DUoS tariffs and for the sake of simplicity, we assume energy tariffs to be fixed and constant in time and location, though our modelling framework can accommodate more general assumptions. Balancing prices span only one time period and are zero for the rest of the horizon. Figure 2 illustrates the coupling of the two problems. The DSO communicates the RT DUoS tariffs to the prosumers, whereas the prosumers react to those tariffs. Thus, the DSO observes their response (demand shift).

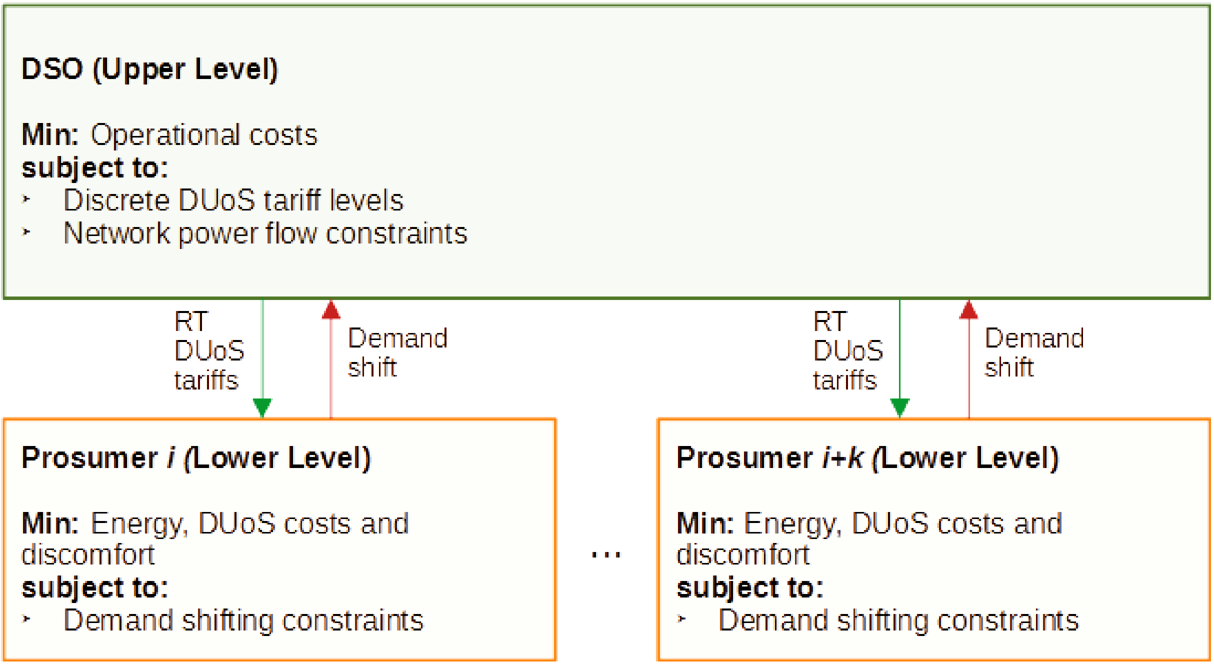

Figure 2: Leader-follower model (bilevel optimisation) of the proposed methodology.

Tariff type: As discussed in D4.4, tariffs in energy can be categorised as volumetric (€/MWh), peak-power or capacity (€/MW) (although peak-power and capacity tariffs can be fundamentally different), and fixed (€). The methodology suggested in both algorithms of the Greek demo focuses on volumetric tariffs that can vary both temporally and spatially. In order to enhance intelligibility and adoptability by the public, we introduce discrete price levels instead of continuous. Moreover, RT DUoS tariffs can optionally include revenue recovery for DSOs. The volumetric tariffs used in the proposed methodology are associated with operational costs.

Prosumer models: In this basic context of the Greek demo, prosumers are assumed to own and operate PV generation. In addition, some of their demand is flexible, meaning that certain assets can move their demand to different hours of the same day. We use generic model to capture the demand flexibility of prosumers. Specific constraints enforce that overall consumption within a day still remains the same, regardless of the shifting that takes place both due to DA and RT tariffs (i.e., demand shifting is energy neutral). However, demand shifting does entail a quantifiable discomfort cost.

Network model: The power flow constraints of the distribution network are represented through the LinDistFlow model [6], [7]. We employ Figure 3 in order to describe notation. The set of distribution nodes is denoted by $\mathcal{I}^+$, while the subset $\mathcal{I}$ does not include the root node. Since we are assuming a radial network, we can also denote the set of branches as $\mathcal{I}$. We denote by j_i the branch ending at node i. Finally, we denote by a_i the parent node of node i and by K_i the set of children nodes of node i.

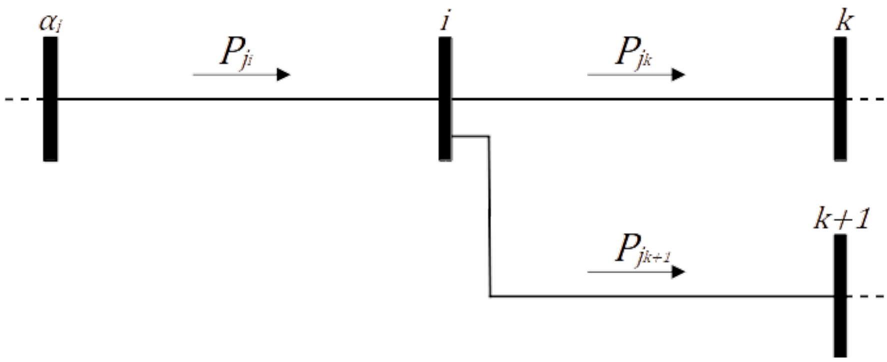

Figure 3: Illustration of part of the distribution network.

3.2 Mathematical formulation

In this section, the mathematical model is discussed. First, we present the upper (DSO) and lower (prosumers) level models and then we transform the bilevel formulation into a Mathematical Problem with Equilibrium Constraints (MPEC) in order to be able to solve effectively. We define each period of the model by (t, d), where t denotes a particular hour and d a particular day.

3.2.1 Nomenclature

Indices and Sets	
$i \in I(I^+)$	Nodes (including the root)
$j_i \in I$	Branch that ends at node i
$\alpha_i \in I$	Parent node of node i
$k \in K_i$	Children nodes of node i
$d \in D$	Day-types
$n \in N$	Tariff levels
$t \in T$	Time periods in horizon ($T \leq H$)
$h \in H$	Time periods in each day
Parameters	
w_d	Number of days in each day-type d
r_{j_i}, x_{j_i}	Resistance, reactance of branch j_i (Ω)

$\overline{F}_{j_i}$	Apparent power limit of branch j_i (MVA)
$\underline{u}_i, \overline{u}_i$	Lower, upper limit of the voltage at node i (V)
$d_{i,t}$	Baseline demand of prosumer at node i and period (t) (MWh)
$\tilde{\alpha}_i$	Demand shifting limit of prosumer at node i
$g_{i,t}$	PV output of prosumer at node i and period (t) (MWh)
π^e	Energy price (€/MWh)
$\pi_t^{b,h}$	Balancing price (€/MWh) at period (t) of the horizon defined at period (h) of the day (€/MWh) – 0 for $t > 1$
π_n	Tariff level n (€/MWh)
$\pi_{i,t,d}$	Ex-ante Distribution use of system (DUoS) tariff at node i and period (t) (MWh) for day-type d
π_i^D	Demand curtailment penalty factor at node i (€/MWh)
π_i^G	Generation curtailment penalty factor at node i (€/MWh)
$d_{i,t}^{\downarrow}$	Demand shifted away from (downwards) due to DA tariffs period (t) for prosumer at node i (MWh)
$d_{i,t}^{\uparrow}$	Demand shifted towards (upwards) period due to DA tariffs (t) for prosumer at node i (MWh)
$\kappa_{i,t}^{dn}$	Discomfort penalty of prosumer at node i associated with shifting demand away from (downwards) period (t) (€/MWh) – analogous to $\kappa_{i,t,d}^{\downarrow}$ of [2]
$\kappa_{i,t}^{up}$	Discomfort penalty of prosumer at node i associated with shifting demand towards (upwards) period (t) (€/MWh) – analogous to $\kappa_{i,t,d}^{\uparrow}$ of [2]
κ^C	Profit margin of DSO
Variables	
$d_{i,t}^{dn}$	Demand shifted away from (downwards) period (t) for prosumer at node i (MWh)
$d_{i,t}^{up}$	Demand shifted towards (upwards) period (t) for prosumer at node i (MWh)
$c_{i,t}^D$	Demand curtailment at node i and period (t) (MWh)
$c_{i,t}^G$	Generation curtailment at node i and period (t) (MWh)
$\lambda_{i,t}$	Real-time Distribution use of system (DUoS) tariff at node i and period (t) (MWh)
$u_{i,t,n}$	Binary variable of tariff level n at node i and period (t) (MWh)

3.2.2 Upper level (DSO)

The upper level expresses the decision-making problem of the DSO. It is formulated as follows:

$$\min_{\mathcal{V_{UL}}} \mathcal{J}^u = \min_{\mathcal{V_{UL}}} \sum_{t \in T} \sum_{i \in I} \left(\pi^D_{i,t} c^D_{i,t} + \pi^G_{i,t} c^G_{i,t} \right) \tag{1a}$$

where

$$\mathcal{V_{UL}} = \{\lambda_{i,t}, u_{i,t,n}, c^D_{i,t}, c^G_{i,t}, P_{j_i,t}, Q_{j_i,t}, v_{i,t}\}$$

subject $\forall i \in I, t \in T$ to:

$$P_{j_i,t} = d_{i,t} - (d^{\downarrow}_{i,t} + d^{dn}_{i,t}) + (d^{\uparrow}_{i,t} + d^{up}_{i,t}) - g_{i,t} - c^D_{i,t} + c^G_{i,t} + \sum_{k \in \mathcal{K}_i} P_{j_k,t} \tag{1b}$$

$$Q_{j_i,t} = (d_{i,t} - (d^{\downarrow}_{i,t} + d^{dn}_{i,t}) + (d^{\uparrow}_{i,t} + d^{up}_{i,t}) - g_{i,t,d} - c^D_{i,t} + c^G_{i,t}) \tan \phi_i + \sum_{k \in \mathcal{K}_i} Q_{j_k,t} \tag{1c}$$

$$P^2_{j_i,t} + Q^2_{j_i,t} \le \overline{F}^2_{j_i} \tag{1d}$$

$$v_{i,t} = v_{a_i,t} - 2\left(r_{j_i} P_{j_i,t} + x_{j_i} Q_{j_i,t}\right) \tag{1e}$$

$$\underline{v}^2_{i,t} \le v_{i,t} \le \overline{v}^2_{i,t} \tag{1f}$$

$$0 \le c^G_{i,t} \le p_{i,t} \tag{1g}$$

$$0 \le c^D_{i,t} \le d_{i,t} - (d^{\downarrow}_{i,t} + d^{dn}_{i,t}) + (d^{\uparrow}_{i,t} + d^{up}_{i,t}) \tag{1h}$$

$$\lambda_{i,t} = \sum_{n \in \mathcal{N}} u_{i,t,n} \pi_n \tag{1i}$$

$$\sum_{n \in \mathcal{N}} u_{i,t,n} = 1 \tag{1j}$$

$$\sum_{t \in T} \sum_{i \in \mathcal{I}} (\pi_{i,t} + \lambda_{i,t})\left(d_{i,t} - (d^{\downarrow}_{i,t} + d^{dn}_{i,t}) + (d^{\uparrow}_{i,t} + d^{up}_{i,t}) - g_{i,t,d} - c^D_{i,t} + c^G_{i,t}\right) = (1 + \kappa^C)\mathcal{J}^u \tag{1k}$$

The objective function (1a) minimizes the total operating cost of the DSO over the shrinking horizon (rest of day). This cost is expressed as the sum of demand curtailment costs (first term) and generation curtailment costs (second term). Constraints (1b) and (1c) express the nodal active and reactive power balance constraints, respectively. Constraints (1d) enforce the apparent power limits of each branch. Constraint (1e) represents the relationship between nodal voltage magnitudes and adjacent power flows, while constraints (1f) enforce voltage limits for each node. Constraints (1g) and (1h) express the curtailment limits of generation and demand at each node. Constraints (1i)-(1j) capture our assumption that the tariff levels are discrete. Finally, constraint (1l) imposes the recovery of the total operating cost of the DSO (augmented by a profit margin) from the collected network charges. The profit margin of the DSO is chosen as a margin above costs that creates a reasonable return which can be employed as an incentive to improve DSO performance on tasks not related to operational cost, e.g., customer services. Our formulation allows for the NRA to set any profit margin, including no margin at all.

3.2.3 Lower level (Prosumer)

The lower level expresses the decision-making problem of the prosumers. It is described by the following model:

$$\min_{\mathcal{V}_{\mathcal{LL}}} \mathcal{J}^{\ell} = \min_{\mathcal{V}_{\mathcal{LL}}} \sum_{t\in T}\sum_{i\in I}\Big[\big(\pi^{e} + \pi_{t}^{RT,h} + \pi_{i,t,d} + \lambda_{i,t}\big)\big(d_{i,t} - (d_{i,t}^{\downarrow} + d_{i,t}^{dn}) + (d_{i,t}^{\uparrow} + d_{i,t}^{up}) - g_{i,t,d}\big) + \kappa_{i,t}^{\downarrow}(d_{i,t}^{\downarrow} + d_{i,t}^{dn}) + \kappa_{i,t}^{\uparrow}(d_{i,t}^{\uparrow} + d_{i,t}^{up})\Big] \quad (2a)$$

where

$$\mathcal{V}_{\mathcal{LL}} = \{d_{i,t}^{dn}, d_{i,t}^{up}\}$$

subject $\forall i \in I, t \in T$ to:

$$(\underline{\theta}_{i,t}, \overline{\theta}_{i,t}): \quad 0 \le d_{i,t}^{dn} \le \alpha_i d_{i,t} - d_{i,t}^{\downarrow} + d_{i,t}^{\uparrow} \quad (2b)$$

$$(\underline{\iota}_{i,t}, \overline{\iota}_{i,t}): \quad 0 \le d_{i,t}^{up} \le \alpha_i d_{i,t} + d_{i,t}^{\downarrow} - d_{i,t}^{\uparrow} \quad (2c)$$

$$(\kappa_i): \quad \sum_{t\in T}\big(-d_{i,t}^{dn} + d_{i,t}^{up}\big) = 0,\ \forall i \in I \quad (2d)$$

The objective function (2a) minimizes the total operating cost of the prosumers. This cost is expressed as the sum of the total electricity payments (first term, including both energy costs and network charges) and the discomfort cost associated with demand shifting (second and third terms). The demand shifting flexibility of the prosumers is expressed by constraints (2b)-(2d). The non-negative variables $d_{i,t,d}^{\downarrow}$ and $d_{i,t,d}^{\uparrow}$ represent the shifting of demand away from and towards period (t) for prosumer i, relative to its respective baseline level $d_{i,t,d}$. Following [8], the upper limits of such demand shifting actions correspond to a ratio α_i of the baseline level. This is expressed by constraints (2b)-(2c). Finally, constraints (2d) ensure that additional demand shifting due to RT tariffs is energy neutral within the remaining of the daily horizon.

3.2.4 Formulation of the Mathematical Program with Equilibrium Constraints (MPEC)

As described in Figure 2, the two problems (upper and lower) are coupled. This means that the optimal solution of the one affects the optimal solution of the other and vice versa. More specifically, the optimal DUoS tariffs of the upper level affect the optimal demand shifting of the lower level, whereas said demand shifting affects the constraints of the upper level. As it is typical with such bilevel optimisation problems, one can replace the lower-level problem with its Karush-Kuhn-Tucker (KKT) conditions [9]. The KKT conditions of the lower lever $\forall i \in \mathcal{I}, t \in \mathcal{T}, d \in \mathcal{D}$ are:

- **Primal constraints:**

$$(2b),\ (2c),\ (2d) \quad (3a)$$

- **Dual constraints**

$$\underline{\theta}_{i,t}, \overline{\theta}_{i,t}, \underline{\iota}_{i,t}, \overline{\iota}_{i,t} \ge 0 \quad (3b)$$

- **Complementary slackness:**

$$\underline{\theta}_{i,t}(-d_{i,t}^{dn}) = 0 \quad (3c)$$

$$\overline{\theta}_{i,t}(d_{i,t}^{dn} - (\alpha_i d_{i,t} - d_{i,t}^{\downarrow} + d_{i,t}^{\uparrow})) = 0 \quad (3d)$$

$$\underline{\iota}_{i,t}(-d_{i,t}^{up}) = 0 \tag{3e}$$

$$\bar{\iota}_{i,t}(d_{i,t}^{up} - (\alpha_i d_{i,t} + d_{i,t}^{\downarrow} - d_{i,t}^{\uparrow})) \tag{3f}$$

- **Gradient of the Lagrangian:**

$(d_{i,t,d}^{\downarrow})$:

$$-\left(\pi^e + \pi_t^{RT,h} + \pi_{i,t} + \lambda_{i,t}\right) + \kappa_{i,t}^{\downarrow} - \underline{\theta}_{i,t} + \overline{\theta}_{i,t} - \kappa_i = 0 \tag{3g}$$

$(d_{i,t,d}^{\uparrow})$:

$$\left(\pi^e + \pi_t^{RT,h} + \pi_{i,t} + \lambda_{i,t}\right) + \kappa_{i,t}^{\uparrow} - \underline{\iota}_{i,t} + \bar{\iota}_{i,t} + \kappa_i = 0 \tag{3h}$$

If one adds the KKT conditions of the lower level as additional constraints to the upper level, one forms a single level problem that is, by definition, equivalent to the bilevel optimisation problem. The new formulation is a Mathematical Program with Equilibrium Constraints (MPEC). The new optimisation problem becomes:

$$\min_{\mathcal{V}_{\mathcal{UL}}} \mathcal{J}^u \tag{4a}$$

where

$$\mathcal{V}_{\text{MPEC}} = \mathcal{V}_{\mathcal{UL}} \cup \mathcal{V}_{\mathcal{LL}} \cup \{\underline{\zeta}_{i,t,d}, \overline{\zeta}_{i,t,d}, \underline{\eta}_{i,t,d}, \overline{\eta}_{i,t,d}, \gamma_{i,d}\}$$

subject to:

$$\text{(1b)-(1k), (3)} \tag{4b}$$

3.2.5 Linearisation of the complementarity conditions

The complementary slackness conditions (3c)-(3f) involve bi-linear terms which can be expressed in the generic form $\delta p = 0$, with δ and p representing dual and primal terms, respectively. The Fortuny-Amat linearization approach [10] replaces each of these conditions with the following set of mixed-integer linear conditions: $\delta \geq 0$, $p \geq 0$, $p \leq z\,M$, $\delta \leq (1-z)M$. Here, z is an auxiliary variable and M is a sufficiently large positive constant. Illustrating an example from the current formulation, Equation (3c) can be linearized as follows $\forall i \in \mathcal{I}, t \in \mathcal{T}, d \in \mathcal{D}$:

$$d_{i,t}^{dn} \leq z_{i,t}^{\underline{\theta}} M \tag{5a}$$

$$\underline{\theta}_{i,t} \leq \left(1 - z_{i,t}^{\underline{\theta}}\right) M \tag{5b}$$

3.2.6 Linearisation of the revenue adequacy constraint

The revenue adequacy constraint (1k) involves four bi-linear terms, namely $\lambda_{i,t} d_{i,t}^{dn}$, $\lambda_{i,t} d_{i,t}^{up}$, $\lambda_{i,t} c_{i,t,d}^{D}$ and $\lambda_{i,t} c_{i,t,d}^{G}$. The first two are linearized by using a subset of the KKT conditions of the lower-level problem.

First, one multiplies (3g) and (3h) with $d_{i,t}^{dn}$ and $d_{i,t}^{up}$, respectively and obtains:

$$-\left(\pi^{e}+\pi_{t}^{RT,h}+\pi_{i,t}+\lambda_{i,t}\right)d_{i,t}^{dn}+\kappa_{i,t}^{\downarrow}d_{i,t}^{dn}-\underline{\theta}_{i,t}d_{i,t}^{dn}+\overline{\theta}_{i,t}d_{i,t}^{dn}-\kappa_{i}d_{i,t}^{dn}=0 \tag{6a}$$

$$\left(\pi^{e}+\pi_{t}^{RT,h}+\pi_{i,t}+\lambda_{i,t}\right)d_{i,t}^{up}+\kappa_{i,t}^{\uparrow}d_{i,t}^{up}-\underline{\iota}_{i,t}d_{i,t}^{up}+\bar{\iota}_{i,t}d_{i,t}^{up}+\kappa_{i}d_{i,t}^{up}=0 \tag{6b}$$

In equation (6a), only the terms $\lambda_{i,t}d_{i,t}^{dn}$, $\underline{\theta}_{i,t}d_{i,t}^{dn}$, $\overline{\theta}_{i,t}d_{i,t}^{dn}$, $\kappa_{i}d_{i,t}^{dn}$ are not linear. $\lambda_{i,t}d_{i,t}^{dn}$ is the one we are trying to replace in (1k). Hence, we focus on the rest. First, (3c) demands that:

$$\underline{\theta}_{i,t}d_{i,t}^{dn}=0 \tag{6c}$$

From (3d) we obtain:

$$\overline{\theta}_{i,t}d_{i,t}^{dn}=(\alpha_{i}d_{i,t}-d_{i,t}^{\downarrow}+d_{i,t}^{\uparrow})\overline{\theta}_{i,t} \tag{6c}$$

Similarly, from (3e) and (3f), for (6b) we obtain:

$$\underline{\iota}_{i,t}d_{i,t}^{up}=0 \tag{6d}$$

$$\bar{\iota}_{i,t}d_{i,t}^{up}=(\alpha_{i}d_{i,t}+d_{i,t}^{\downarrow}-d_{i,t}^{\uparrow})\bar{\iota}_{i,t} \tag{6e}$$

Using the above, one has (almost) linear equations to replace $\lambda_{i,t}d_{i,t}^{dn}$ and $\lambda_{i,t}d_{i,t}^{up}$. The terms $\kappa_{i}d_{i,t}^{dn}$ and $\kappa_{i}d_{i,t}^{up}$ are dealt with shortly:

$$-\lambda_{i,t}d_{i,t}^{dn}=-\left[-\left(\pi^{e}+\pi_{t}^{RT,h}+\pi_{i,t}\right)d_{i,t}^{dn}+\kappa_{i,t}^{\downarrow}d_{i,t}^{dn}+(\alpha_{i}d_{i,t}-d_{i,t}^{\downarrow}+d_{i,t}^{\uparrow})\overline{\theta}_{i,t}-\kappa_{i}d_{i,t}^{dn}\right]=0 \tag{6f}$$

$$\lambda_{i,t}d_{i,t}^{up}=-\left[\left(\pi^{e}+\pi_{t}^{RT,h}+\pi_{i,t}\right)d_{i,t}^{up}+\kappa_{i,t}^{\uparrow}d_{i,t}^{up}+(\alpha_{i}d_{i,t}+d_{i,t}^{\downarrow}-d_{i,t}^{\uparrow})\bar{\iota}_{i,t}+\kappa_{i}d_{i,t}^{up}\right]=0 \tag{6g}$$

Summing $\forall i\in I, t\in T$ one obtains:

$$\begin{aligned}\textstyle\sum_{t\in T}\sum_{i\in I}\lambda_{i,t}\left(-d_{i,t}^{dn}+d_{i,t}^{up}\right)=&-\textstyle\sum_{t\in T}\sum_{i\in I}\left[\left(\pi^{e}+\pi_{t}^{RT,h}+\pi_{i,t}\right)\left(-d_{i,t}^{dn}+d_{i,t}^{up}\right)+\kappa_{i,t}^{\downarrow}d_{i,t}^{dn}+\kappa_{i,t}^{\uparrow}d_{i,t}^{up}+\right.\\&\left.(\alpha_{i}d_{i,t}-d_{i,t}^{\downarrow}+d_{i,t}^{\uparrow})\overline{\theta}_{i,t}+(\alpha_{i}d_{i,t}+d_{i,t}^{\downarrow}-d_{i,t}^{\uparrow})\bar{\iota}_{i,t}\right]-\textstyle\sum_{i\in I}\kappa_{i}\sum_{t\in T}\left(-d_{i,t}^{dn}+d_{i,t}^{up}\right)\end{aligned} \tag{6h}$$

However, we know from (2d) that the term $\sum_{t\in T}(-d_{i,t}^{dn}+d_{i,t}^{up})=0$, hence $\sum_{i\in I}\kappa_{i}\sum_{t\in T}(-d_{i,t}^{dn}+d_{i,t}^{up})=0$.

Therefore, (6h) becomes:

$$\begin{aligned}\textstyle\sum_{t\in T}\sum_{i\in I}\lambda_{i,t}\left(-d_{i,t}^{dn}+d_{i,t}^{up}\right)=&-\textstyle\sum_{t\in T}\sum_{i\in I}\left[\left(\pi^{e}+\pi_{t}^{RT,h}+\pi_{i,t}\right)\left(-d_{i,t}^{dn}+d_{i,t}^{up}\right)+\kappa_{i,t}^{\downarrow}d_{i,t}^{dn}+\kappa_{i,t}^{\uparrow}d_{i,t}^{up}+\right.\\&\left.(\alpha_{i}d_{i,t}-d_{i,t}^{\downarrow}+d_{i,t}^{\uparrow})\overline{\theta}_{i,t}+(\alpha_{i}d_{i,t}+d_{i,t}^{\downarrow}-d_{i,t}^{\uparrow})\bar{\iota}_{i,t}\right]\end{aligned} \tag{6i}$$

Overall, (1k) becomes:

$$\begin{aligned}&\sum_{t\in T}\sum_{i\in\mathcal{I}}\pi_{i,t}\left(d_{i,t}-(d_{i,t}^{\downarrow}+d_{i,t}^{dn})+(d_{i,t}^{\uparrow}+d_{i,t}^{up})-g_{i,t,d}-c_{i,t}^{D}+c_{i,t}^{G}\right)\\&\qquad+\sum_{t\in T}\sum_{i\in\mathcal{I}}\lambda_{i,t}\left(d_{i,t}-d_{i,t}^{\downarrow}+d_{i,t}^{\uparrow}-g_{i,t,d}-c_{i,t}^{D}+c_{i,t}^{G}\right)+\sum_{t\in T}\sum_{i\in\mathcal{I}}\lambda_{i,t}\left(-d_{i,t}^{dn}+d_{i,t}^{up}\right)\\&\qquad=(1+\kappa^{C})\mathcal{J}^{u}\Rightarrow\end{aligned}$$

$$\sum_{t\in T}\sum_{i\in \mathcal{I}} \pi_{i,t}\big(d_{i,t}-(d_{i,t}^{\downarrow}+d_{i,t}^{dn})+(d_{i,t}^{\uparrow}+d_{i,t}^{up})-g_{i,t,d}-c_{i,t}^{D}+c_{i,t}^{G}\big) \\ +\sum_{t\in T}\sum_{i\in \mathcal{I}} \lambda_{i,t}\big(d_{i,t}-d_{i,t}^{\downarrow}+d_{i,t}^{\uparrow}-g_{i,t,d}-c_{i,t}^{D}+c_{i,t}^{G}\big) \\ -\sum_{t\in T}\sum_{i\in I}\big[\big(\pi^{e}+\pi_{t}^{RT,h}+\pi_{i,t}\big)\big(-d_{i,t}^{dn}+d_{i,t}^{up}\big)+\kappa_{i,t}^{\downarrow}d_{i,t}^{dn}+\kappa_{i,t}^{\uparrow}d_{i,t}^{up}+(\alpha_i d_{i,t}-d_{i,t}^{\downarrow} \\ +d_{i,t}^{\uparrow})\overline{\theta}_{i,t}+(\alpha_i d_{i,t}+d_{i,t}^{\downarrow}-d_{i,t}^{\uparrow})\overline{\iota}_{i,t}\big]=(1+\kappa^{C})\mathcal{J}^{u} \tag{7}$$

The last two bi-linear terms are linearized through binary expansion. For example, for $\lambda_{i,t}c_{i,t,d}^{D}$, one can write:

$$\lambda_{i,t}c_{i,t,d}^{D}=\sum_{n\in\mathcal{N}}u_{i,t,n}\pi_{n}c_{i,t}^{D} \tag{8a}$$

This expansion results in the multiplication of the binary variable $u_{i,t,n}$ with the continuous variable $c_{i,t,d}^{D}$. We therefore introduce the auxiliary variable $z_{i,t,n}^{D}$, where:

$$u_{i,t,n}c_{i,t}^{D}=z_{i,t,n}^{D} \tag{8b}$$

$$0\le c_{i,t}^{D}-z_{i,t,n}\le M_1\big(1-u_{i,t,n}\big) \tag{8c}$$

$$0\le z_{i,t,n}\le M_1 u_{i,t,n} \tag{8d}$$

Thus, we obtain:

$$\lambda_{i,t}c_{i,t}^{D}=\sum_{n\in\mathcal{N}}\pi_{n}z_{i,t,n}^{D} \tag{8e}$$

Then (1k) becomes:

$$\sum_{t\in T}\sum_{i\in \mathcal{I}} \pi_{i,t}\big(d_{i,t}-(d_{i,t}^{\downarrow}+d_{i,t}^{dn})+(d_{i,t}^{\uparrow}+d_{i,t}^{up})-g_{i,t,d}-c_{i,t}^{D}+c_{i,t}^{G}\big) \\ +\sum_{t\in T}\sum_{i\in \mathcal{I}} \lambda_{i,t}\big(d_{i,t}-d_{i,t}^{\downarrow}+d_{i,t}^{\uparrow}-g_{i,t,d}\big)+\sum_{t\in T}\sum_{i\in \mathcal{I}}\sum_{n\in\mathcal{N}}\pi_{n}(z_{i,t,n}^{D}+z_{i,t,n}^{G}) \\ -\sum_{t\in T}\sum_{i\in I}\big[\big(\pi^{e}+\pi_{t}^{RT,h}+\pi_{i,t}\big)\big(-d_{i,t}^{dn}+d_{i,t}^{up}\big)+\kappa_{i,t}^{\downarrow}d_{i,t}^{dn}+\kappa_{i,t}^{\uparrow}d_{i,t}^{up}+(\alpha_i d_{i,t}-d_{i,t}^{\downarrow} \\ +d_{i,t}^{\uparrow})\overline{\theta}_{i,t}+(\alpha_i d_{i,t}+d_{i,t}^{\downarrow}-d_{i,t}^{\uparrow})\overline{\iota}_{i,t}\big]=(1+\kappa^{C})\mathcal{J}^{u} \tag{9}$$

After the linearization of the complementarity conditions and the revenue adequacy constraints, the MPEC is transformed to a Mixed-Integer Quadratic Program (MIQP) which can be tackled by commercial solvers.

4 Testing Framework

4.1 Revisiting the ex-ante Network Tariff Design modules

Figure 4 illustrates the framework used in D4.4 [2]. In that framework, yearly historic data are used to perform a good clustering of the different day-types for which tariffs are designed. Centralised OPFs are used to extract more usable features. The NTD model of Section 3.3 in D4.4 is used to design the DUoS tariffs. The efficacy of the designed tariffs and of the clustering technique is validated using out-of-sample testing on yearly data where, aggregators/prosumers consider/react to the tariffs and set their DER setpoints accordingly. Finally, the DSO performs any mitigation actions, here curtailment, to keep the network within limits.

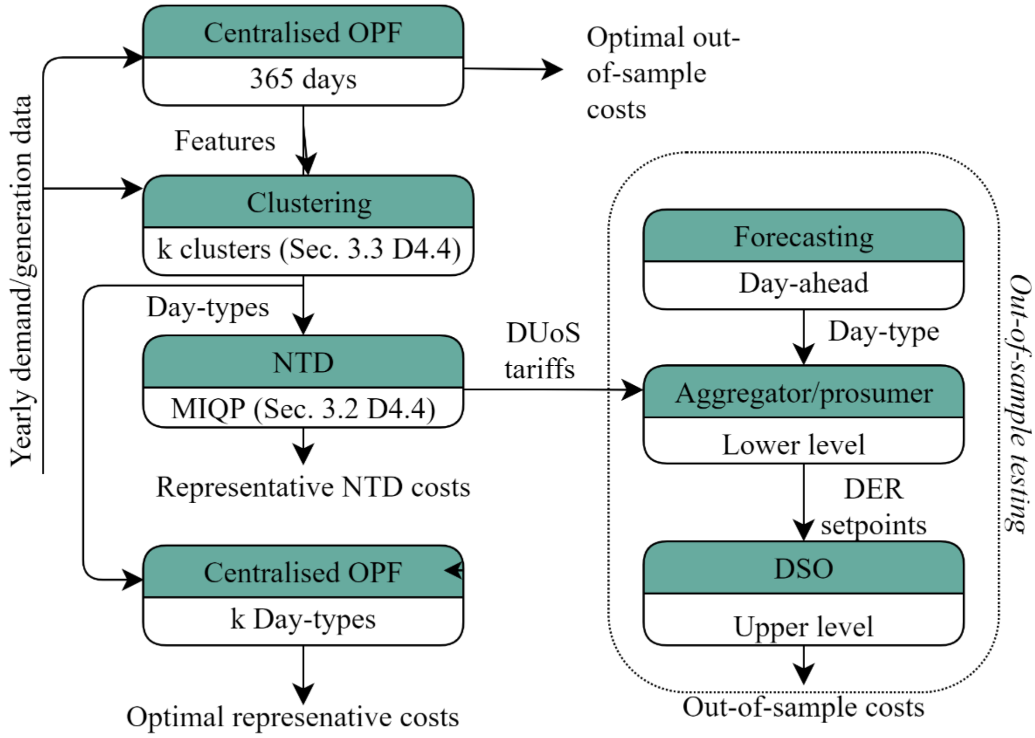

Figure 4: Illustration of modules used in the overall ex-ante NTD framework of D4.4 [2].

4.2 RT Network Tariff Design modules

Figure 5 illustrates the modules used in this deliverable for the RT DUoS tariff design and validation. In the Day-ahead, all stakeholders know the day-type and the corresponding ex-ante DUoS tariffs. When the process is initiated, the RT tariffs are designed and sent to the aggregators/prosumers. They consider the RT tariffs along with the ex-ante tariffs and set their DER setpoints. Finally, the DSO performs mitigation actions in the form of curtailment.

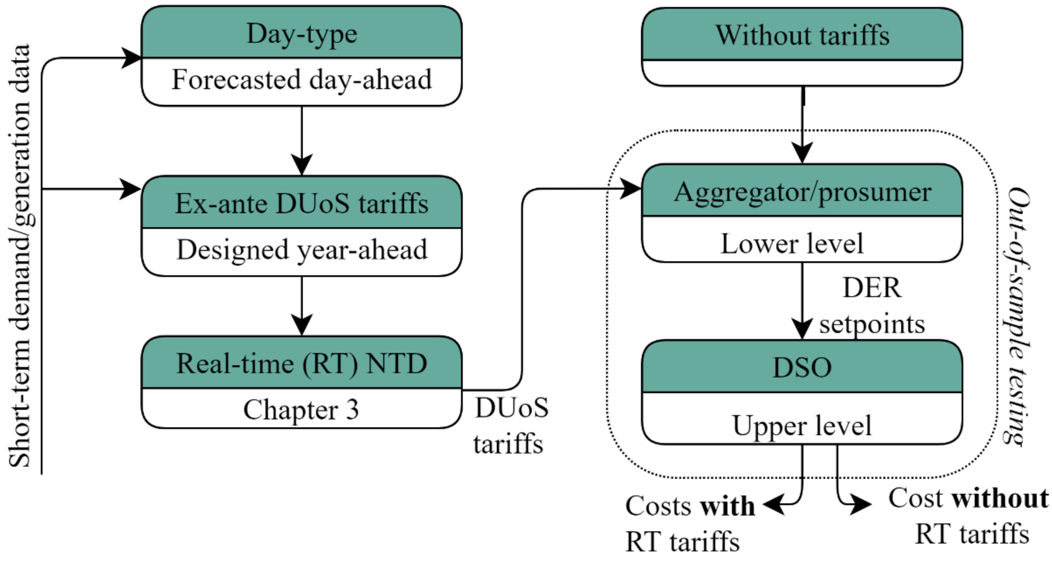

Figure 5: Illustration of modules used in the RT DUoS tariff framework (both design and validation) presented in this deliverable.

4.2.1 Real-time (RT) Network tariff design (NTD) model module

This module is the core model of the methodology. It is the formulation described in Chapter 3, starting from the bilevel model with its final form being the single level MPEC model. This model is implemented on the remaining day when the module is triggered.

4.2.2 Prosumer model module

This module simulates the decision-making problem of the prosumers and corresponds to the lower-level problem of Chapter 3. The inputs to the model are the network tariffs that are assigned to each day. The outputs are the optimal demand shifting actions of the aggregators/prosumers, see also Figure 5 and Figure 6.

4.2.3 DSO model module

This module simulates the decision-making problem of the DSO and corresponds to the upper-level problem of Chapter 3. Its inputs are the demand shifting actions of the prosumers. The outputs are the optimal curtailment actions and operating costs of the DSO.

4.3 Validation setup

4.3.1 Interaction with ex-ante DUoS Tariffs

The tariff design model of Chapter 3 builds upon the DUoS tariff design framework of D4.4 [2]. Figure 6 illustrates that framework, as presented in the corresponding deliverable. One of the key aspects of the framework is that the DUoS tariffs are communicated to the prosumers/aggregators day-ahead (DA). Moreover, the tariffs that are communicated are of the few (4 in our example) already known patterns that were designed in the beginning of the year. Hence, the end-users are well prepared to take into account and react optimally to the tariffs.

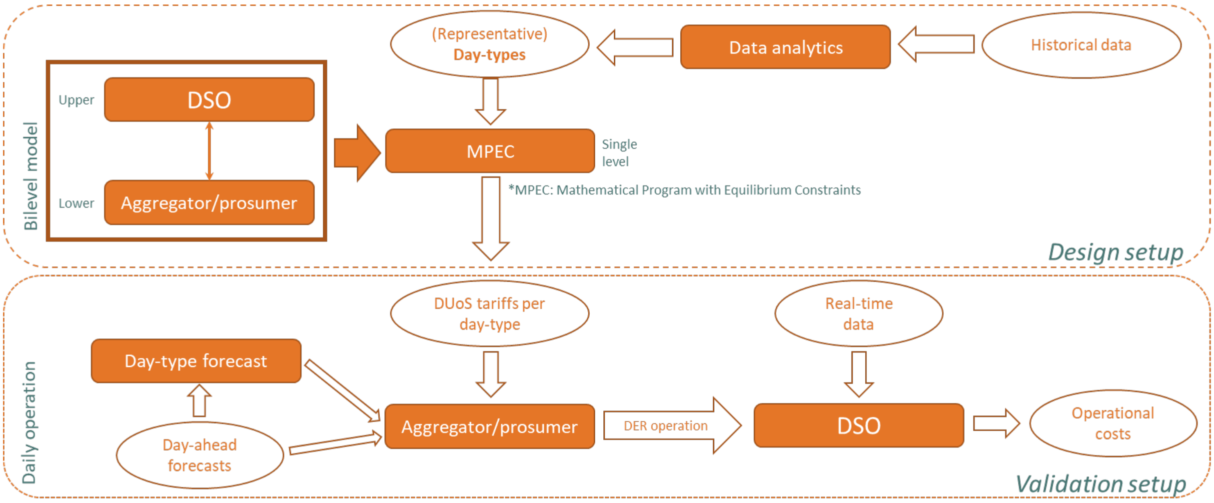

Figure 6: Overall design and validation setups of the ex-ante DUoS tariff framework [2] that precedes the RT tariff design model of Chapter 3.

The model, presented in this deliverable, complements that of D4.4. This means that the tariffs that are designed are added to the DA DUoS tariffs. Not only that, they also follow price-level quantisation, similar to what was used in D4.4. This enhances interpretability and clarity for the end user. Figure 7 describes that testing framework of the RT DUoS tariffs. Compared to the ex-ante tariffs (where there is a design stage that is taking place year-ahead, the tariff pattern choice taking place day-ahead and the validation which is performed during the daily operation) the RT framework takes place in short-term, close to real-time context (in practice hour-ahead, although it can be shorter).

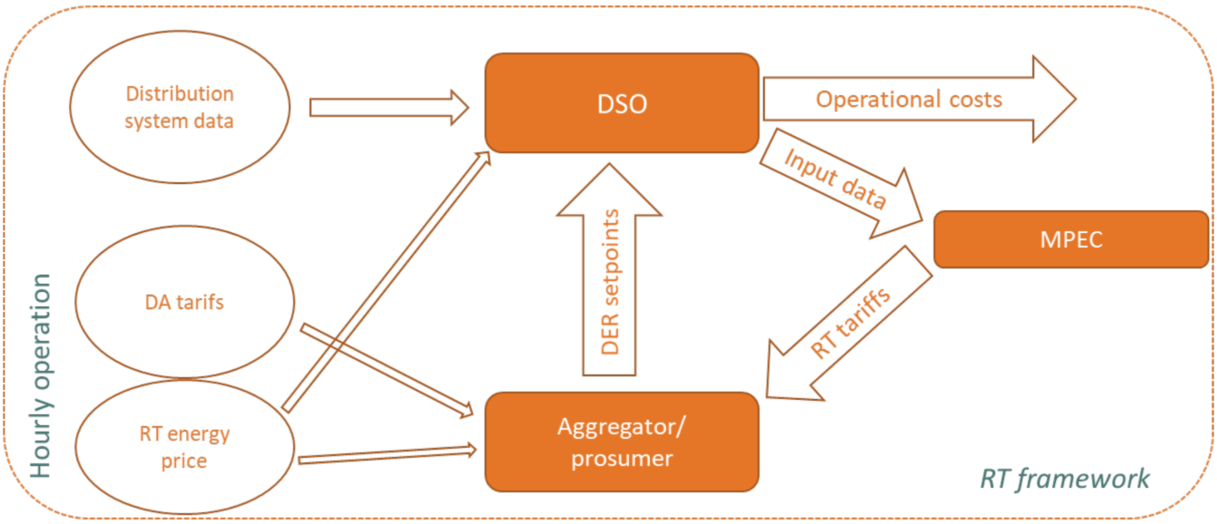

Figure 7: RT tariff utilisation framework

The DSO is notified, either by end users or (preferably) by the TSO, about the need for short-term utilisation of energy products in a particular part of the distribution system. The most common case is balancing market needs. Using the real-time data from the distribution network for the next period, it runs the tariffs design model and communicates the tariffs to the distribution network users (aggregators, prosumers). In turn, the DSO considers these tariffs, along with ex-ante tariffs and other pricing schemes, and optimises its behaviour producing the corresponding setpoints for their DERs. Finally, the DSO performs any congestion mitigation actions, here curtailment, that results to the corresponding operational costs.

4.4 Assumptions and Input Data

4.4.1 Tariff types

In D4.4, the hourly-loc tariffs scheme, by far, outperformed the other two (flat, hourly). The case studies assume that the ex-ante DUoS tariff is hourly-loc. Moreover, the only RT tariff scheme explored is also of the hourly-loc type.

Hourly-loc tariffs

This constitutes the case with the highest spatial-temporal granularity. In this case, the tariffs can vary by both hour and network node. This case is implemented through the MPEC model of Chapter 3 without any modifications. Hourly-loc is short for hourly-locational and refers to the spatial granularity.

4.4.2 Network data

As with D4.4, the case studies are carried out on a model of a rural medium voltage distribution feeder in Greece, see Figure 8, with 12 prosumers. Table 1 summarises basic input data.

Table 1: Summary of basic input data

Parameter	Value
Voltage limits	[0.9,1.1] p.u.
Power factor	0.95
Energy price	75 €/MWh
Balancing price	-150 €/MWh
Ex-ante network tariff levels	[-60, -40, -20, 0, 20, 40, 60] €/MWh
RT network tariff levels	[-180, -120, -60, 0, 60, 120, 180] €/MWh
Generation curtailment penalty factor	115 €/MWh
Demand curtailment penalty factor (active prosumers)	200 €/MWh
Demand curtailment penalty factor (passive prosumers)	400 €/MWh
Profit Margin of the DSO	20%
Hour for which the method is triggered	13:00-14:00

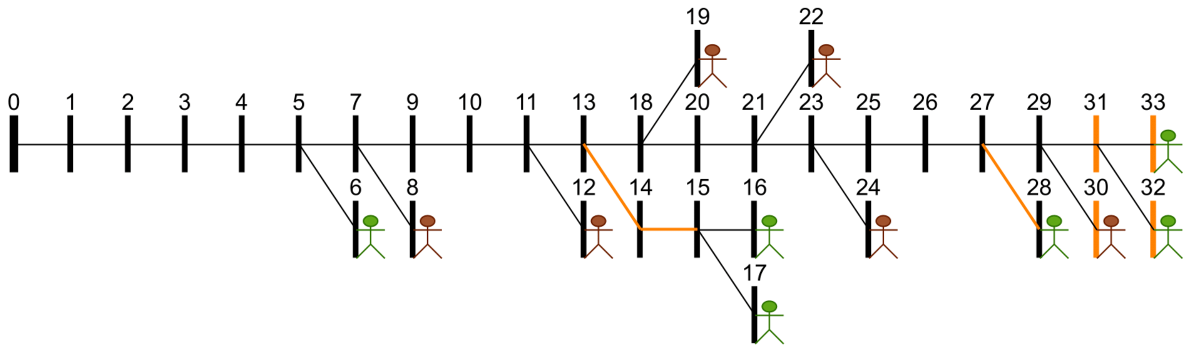

Figure 8: Illustration of rural medium voltage feeder employed in the case studies.

In Figure 8, Passive and active prosumers are indicated by brown and green colour, respectively. Orange colour indicates network branches and nodes with regular congestion

In D4.4, we analysed the network using the available historical demand and PV output data. We found that the following network congestion effects emerge regularly:

a) the thermal limits of the branches between nodes 13-15 are breached during midday and evening hours due to high demand,
b) the thermal limit of the branch between nodes 27 and 28 is breached during midday hours due to high PV output,
c) the lower voltage limits of nodes 30, 31, 32 and 33 are breached during evening hours due to high demand (see also Figure 8).

We assume that prosumers at nodes 8, 12, 19, 22, 24, and 30 are passive. This implies that they do not exhibit demand shifting flexibility. The demand shifting limit of the remaining (active) prosumers is assumed to be identical and varies between 0% and 30% in the scenarios that we examine below.

The discomfort penalty associated with shifting demand towards a particular period (t, d) is assumed to be proportional to the baseline demand at (t, d). This implies that prosumers feel less comfortable about shifting demand towards periods during which they already operate many of their loads.

On the other hand, the discomfort penalty associated with shifting demand away from a particular period (t, d) is assumed to be inversely proportional to the baseline demand at (t, d). This implies that prosumers feel less comfortable about shifting demand away from periods during which they operate few of their loads.

4.5 Testing equipment characteristics

The proposed model has been implemented in Julia [11] using the package JuMP [12] and solved using the optimisation software Gurobi [13] on a computer with a 4-core 2.6 GHz Intel(R) XCore(TM) i7-4720HQ processor and 16 GB of RAM.

5 Case studies

The case studies presented in this Chapter aim at proving the functionality and effectiveness of the RT DUoS tariffs. In order to do so, we base our studies on the main case study of D4.4 [2], the case of 4 clusters, i.e. day-types for which ex-ante tariffs are designed. We assume those are the tariffs that the aggregators know and use and that each day at noon, they are notified which day-type will be applied the next day. In the next section, we assume that at a given hour within a day, the TSO asks to make use of DER flexibility from the distribution network and in response the DSO produces RT DUoS tariffs. The 14th hour of the day is chosen in all case studies as an example. First, we show in detail the result for a single instance where the method is triggered and then, we show cumulative results, for an entire year.

5.1 The ex-ante DA network tariffs

To demonstrate the effectiveness of the RT network tariff method, we make use of the case study illustrated in D4.4 [2]. We use the same network, historic and out-of-sample data. Figure 9, Figure 10, Figure 11, and Figure 12 show the tariffs that was designed for each day-type. This pattern is considered a parameter as described in Section 3.2.

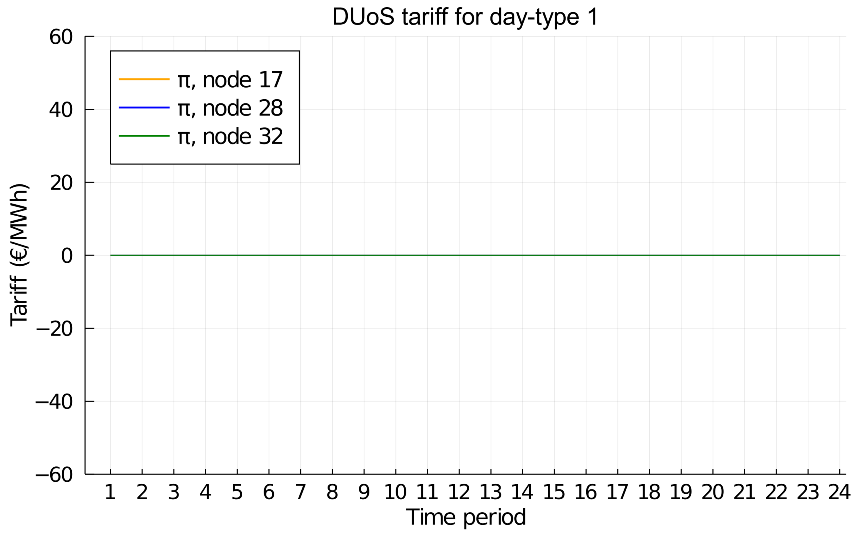

Figure 9: Ex-ante DA DUoS tariffs at 3 nodes as suggested in the main case study of D4.4 for day-type 1.

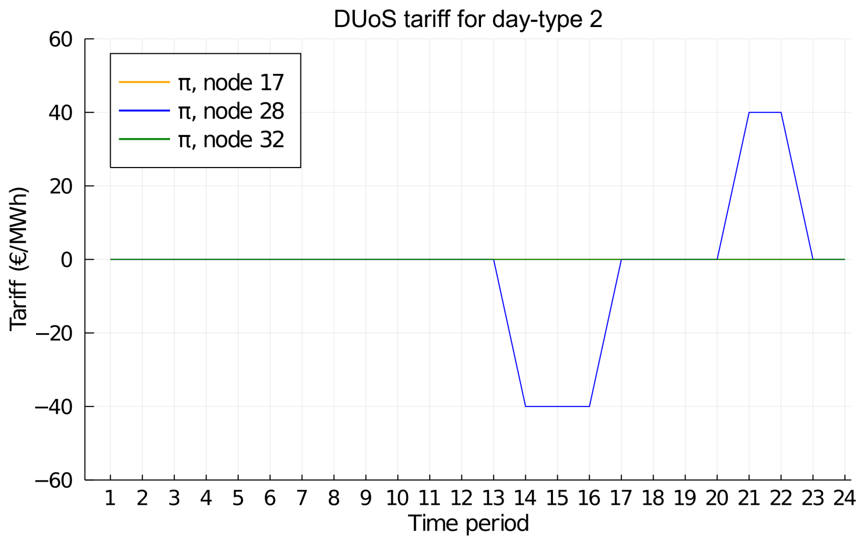

Figure 10: Ex-ante DA DUoS tariffs at 3 nodes, as suggested in the main case study of D4.4 for day-type 2.

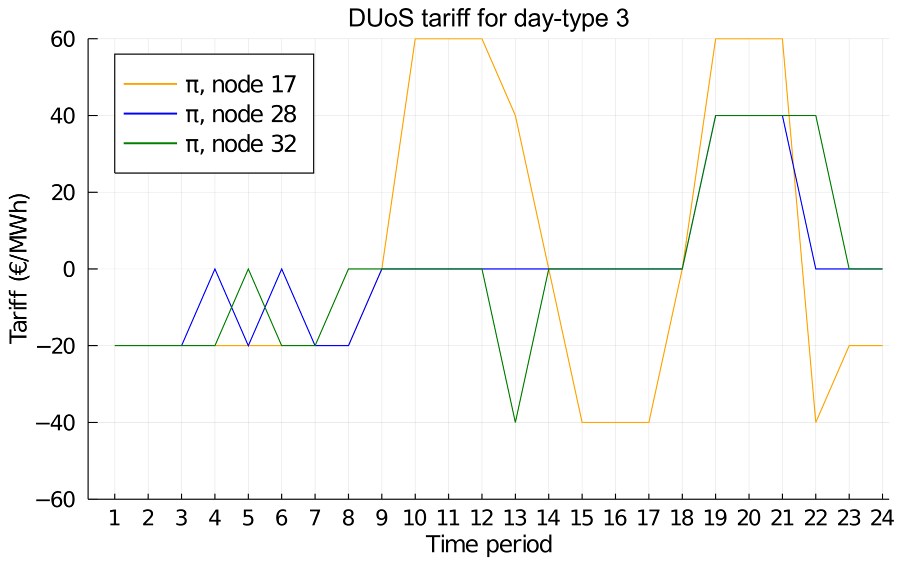

Figure 11: Ex-ante DA DUoS tariffs at 3 nodes as suggested in the main case study of D4.4 for day-type 3.

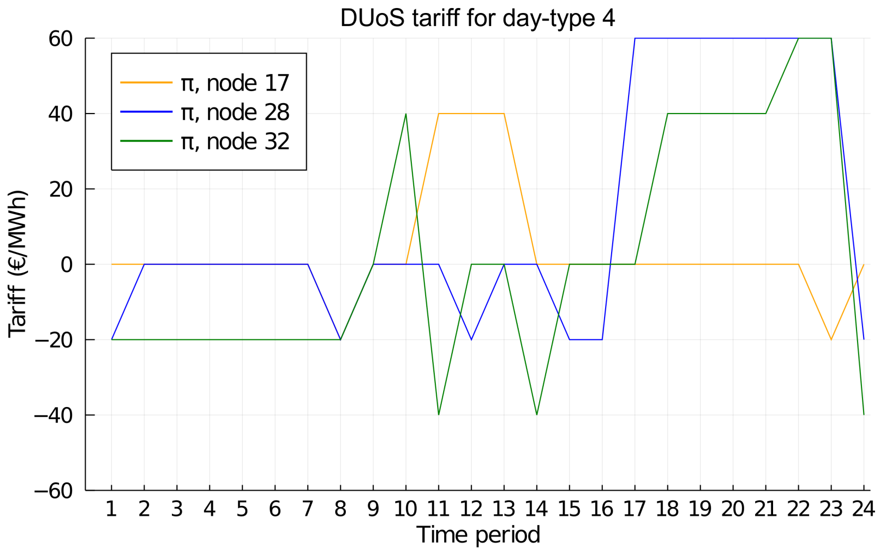

Figure 12: Ex-ante DA DUoS tariffs at 3 nodes as suggested in the main case study of D4.4 for day-type 4.

5.2 Validation of the RT network tariffs

This section illustrates the application of the RT DUoS tariffs on top of the DA DUoS tariffs. First, we present in detail one instance where the RT tariffs are used. Then, we present the overall costs for applying the method daily throughout a year.

5.2.1 Single instance of application of RT DUoS tariffs

We follow nodes 17, 28 and 32 in our illustration which are the same nodes used in the case studies of D4.4 in order to build on the same illustration. The day chosen in this example is the 8^{th} day of the year (8^{th} of January) which belongs in day-type 3 according to the clustering result of the previous deliverable. Thus, the aggregators/prosumer are being charged using the tariff pattern of Figure 11. Shortly before hour 14, the TSO projects that during the next hour, balancing energy will be necessary. The aggregator located in the distribution network has agreed that in cases like this is willing to offer as much energy as possible at a constant price. Before deciding how much energy to offer, the aggregator has to include in the calculation the RT DUoS tariffs the DSO is broadcasting. These tariffs are triggered now but the design includes the whole of the rest of the day. This is due to the fact that many DER offer energy with intertemporal constraints (e.g., demand shifting) hence, a single tariff for the hour of interest could postpone network problems to late in the day.

The calculated tariff pattern is illustrated in Figure 13. One can see that the tariff spans from hour 14 to 24. At node 17, there is a high tariff for the first hour, zero the next and a negative tariff later. This tariff acts against the balancing price, incentivising the aggregator to avoid shifting demand towards the 14th hour as it will cause congestion and therefore curtailment. The tariffs at the other two nodes are zero for the entire horizon.

Figure 14 and Figure 15 show the curtailment produced in the cases without and with the proposed methodology. In Figure 14, we see that, if RT tariffs are not used, the aggregator at node 17 shifts energy towards that hour to take advantage of the high balancing prices. This has the resulting effect of the DSO being forced to curtail its demand power in hour 14 (and compensate the aggregator for the curtailment - remember, this compensation is paid by all customers at the end!). Demand or generation curtailment for the other two nodes and generation curtailment for node 17 is zero for the entire horizon. In the case where the RT tariff is used, the aggregator at node 17 avoids performing the demand shifting and curtailment is avoided. As a result, all demand and generation curtailment for the three nodes of the example is zero for the entire horizon, as shown in Figure 15. By using the tariffs, the DSO has successfully indicated to the aggregator that network usage is very expensive at this hour and the aggregator has included this fact into its decision.

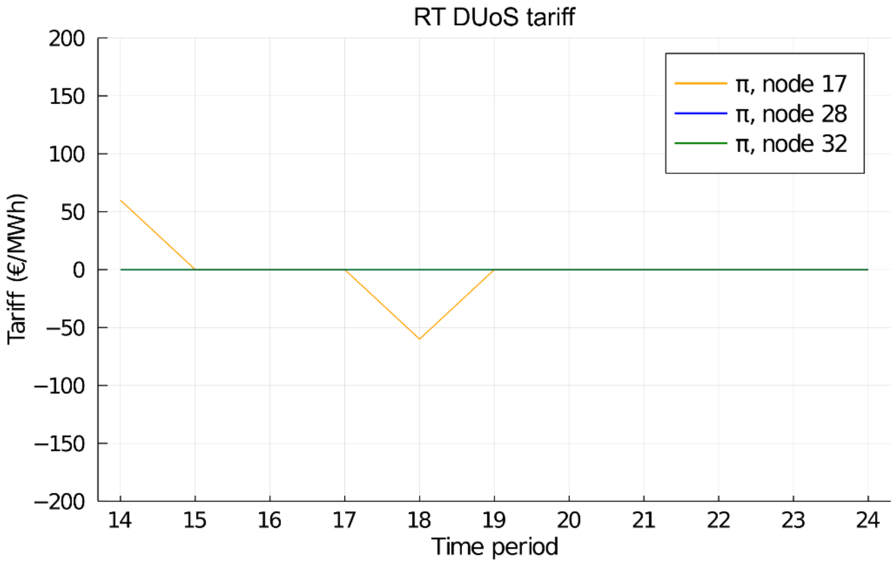

Figure 13: RT DUoS tariffs at 3 nodes as produced by the proposed methodology for triggered during hour 14 of day 8 (day-type 3).

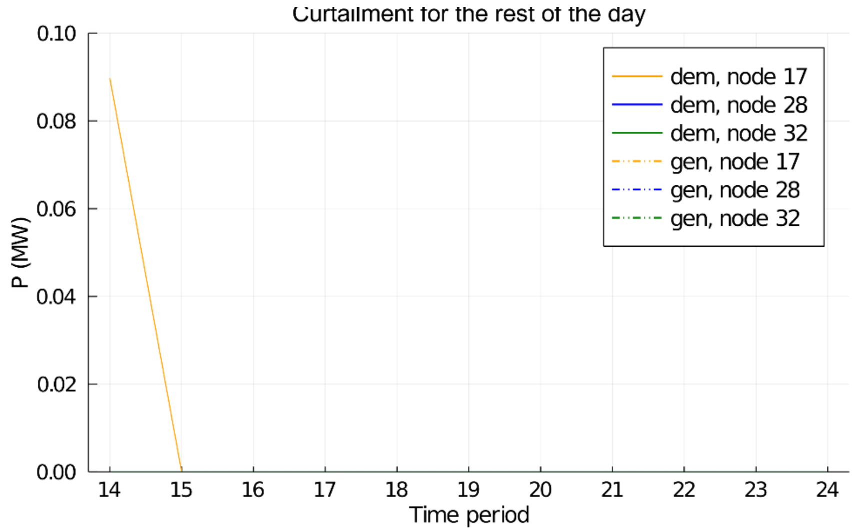

Figure 14: Demand (dem.) and Generation (gen.) Curtailment at 3 nodes as produced without the proposed methodology for an instance that occurred at hour 14 of day 8 (day-type 3).

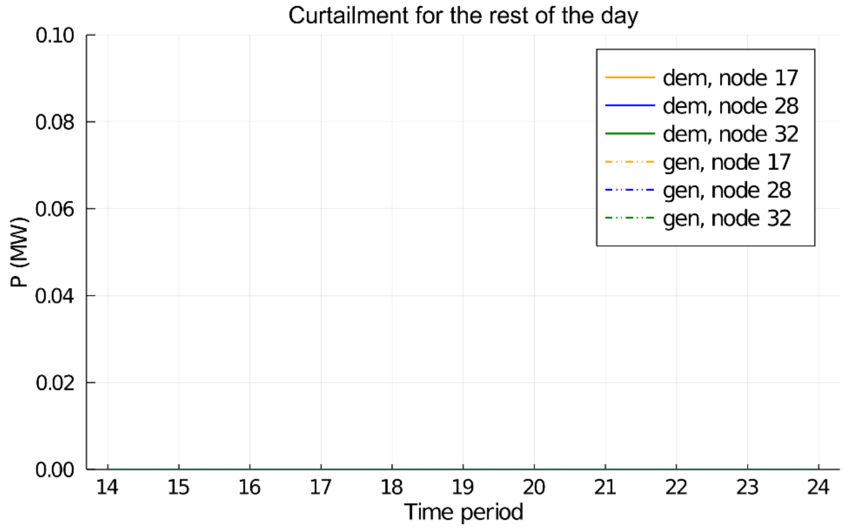

Figure 15: Demand (dem.) and Generation (gen.) Curtailment at 3 nodes as produced with the proposed methodology for an instance that occurred at hour 14 of day 8 (day-type 3).

Table 2 shows that total curtailment costs produced with and without the proposed methodology for the instance of this section. When the proposed method is used, the curtailment costs are zero. This is not the case in every instance of day-type 3, as we will see clearly in the next section.

Table 2: Operational (curtailment) costs as produced without and with the proposed methodology for an instance that occurred at hour 14 of day 8 (day-type 3).

	Without RT tariffs	With RT tariffs	Decrease	Decrease (%)
Operational costs (€)	26.971 €	0 €	26.971 €	100%

5.2.2 Aggregate results for a year

In this section, we perform a year-long analysis on the costs produced without and with the proposed methodological framework of the RT DUoS tariffs. There are no real instances for which the TSO has requested flexibility from the distribution network, because such a framework does not exist yet in many European countries, including Greece. Therefore, we cannot use real instances and measure the curtailment savings of the method. The next best option is to assume random cases where the overall system has flexibility needs that could be served by distribution flexibility. To make all results comparable, avoid any possibility of inconsistent results, and continue our example from Chapter 5.2.1, we fix the hour of the instances as the 14th hour of each day. Each day of the year, we assume a request for flexibility is arriving shortly before 13.00 and that the DSO is designing and disseminating RT DUoS tariffs. Of course, this is something that is impossible to happen, and, in the near future at least, such requests will not be an everyday event. However, this experiment, allows us to quantify the volume and level of operational costs reduction according to each day-type and overall.

Table 3 presents the overall operational costs per day-type and in total. The most obvious observation is that there is a significant variation in the percentage-wise effectiveness of the method per day-type. Day-types 1 and 3 have over 50% reduction, compared to a moderate 25% of day-type 2 and less than 10% of day-type 1. The explanation of these differences is in the conditions of the network per day-type, discussed in detail in D4.4.

Day-type 4 is a very congested day-type. There are a lot of limit violations that required curtailment throughout the day. In such conditions, the DA tariffs of D4.4, make use of almost all of the available flexibility and, as a result, when the TSO request arrives, the RT tariffs can motivate little flexibility volume to address the additional problems. For day-type 2 days, there are mostly line congestion problems due to excessive PV production, during summer. Thus, a similar problem occurs, where the available flexibility is already used for other purposes, but applies to fewer nodes. At nodes not suffering from excessive PV, the method is effective, hence, a 25% reduction, compared to 10% for day-type 4.

Day-type 3 is a lightly congested day, where not all flexibility is used by the DA tariffs. Thus, there is volume available to be used for the problems that occur due to the TSO balancing request. Moreover, day-type 1 is the by far the most common day-type, where network problems do not occur. Thus, not only much less curtailment occurs, even without the proposed tariffs, but the RT tariffs are nearly 87% effective in its reduction.

Table 3: Summary of operational (curtailment) costs for different day-types throughout the year without and with the use of RT network tariffs.

Operational costs (€)	**Without RT tariffs**	**With RT tariffs**	**Decrease**	**Decrease (%)**
Day-type 1	905.74 €	121.2 €	784.5 €	86.61%
Day-type 2	3468.95 €	2587.17 €	881.77 €	25.42%
Day-type 3	1822.32 €	839.40 €	982.92 €	53.94%
Day-type 4	6603.19 €	5981.60 €	621.59 €	9.41%
Total	12800.20 €	9529.37 €	3270.78 €	25.55%

6 Conclusion

The current report presents the design and development of the framework and the corresponding tool for ancillary services to the TSO that will be deployed in the Greek demo. As with the algorithm for DER control, at the core of the tool lies a novel design for variable DUoS tariffs that aims at mobilizing DER flexibility while at the same time retaining all traditional DUoS tariff properties such as simplicity for the end-user. The report suggests a RT DUoS tariffs methodology that works in conjunction with the ex-ante DA DUoS methodology of the previous deliverable of optimal DER control (D4.4).

Similarly, to D4.4, the design is based on a bilevel optimization model, capturing the interaction between a DSO designing the DUoS tariffs at the upper level, and prosumers with PV generation and flexible demand DERs who react to the tariffs at the lower level. In contrast to past efforts on tariffs and analogously to D4.4, this model considers a detailed representation of the distribution network power flow constraints, different levels of temporal and spatial granularity in the designed tariffs, as well as discrete tariff levels for preserving intelligibility.

To test the proposed methodology, a design and validation setup is built where, different modules are created to properly simulate the actions of all actors and real historical data are used. Moreover, the case studies are built with the synergy of DA and RT tariffs as their basic feature. The case studies simulate and measure the efficacy of the method when requests for services from the TSO arrive to aggregators/consumers located in distribution networks. The results demonstrate that when deployed, the proposed methodology can significantly decrease operational costs for DSOs compared to the case where it is not.

The main conclusion is that a RT tariff scheme, complementary to the DA DUoS tariffs, can significantly reduce costs in cases where distribution network problems occur due to DER flexibility being used for balancing or reserve services to the TSO.

7 List of Tables

8 List of Figures

9 List of References

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10 List of Abbreviations

Abbreviation	Term
API	Application Program Interface
DA	Day-Ahead
DER	Distributed Energy Resources
DSO	Distribution System Operator
DUoS	Distribution Use-of-System
ID	Intra-Day
KKT	Karush-Kuhn-Tucker
KPI	Key Performance Indicator
LinDist	Linear Distribution Power Flow
MIQP	Mixed-Integer Quadratically constrained Program
MPEC	Mathematical Program with Equilibrium Constraints
NRA	National Regulatory Authority
NTD	Network Tariff Design
PV	Photovoltaic
RT	Real-Time
OPF	Optimal Power Flow
TSO	Transmission System Operator