Deliverable 5.2.

Standardized interoperable flexibility provisioning by avoiding grid congestion

Contributors:

With the support from:

Funding from:

Supported by:

Federal Ministry for Economic Affairs and Climate Action

on the basis of a decision by the German Bundestag

Dieses Projekt wird aus Mitteln der FFG gefördert. www.ffg.at

This project has received funding in the framework of the joint programming initiative ERA-Net Smart Energy Systems' focus initiative Digital Transformation for the Energy Transition, with support from the European Union's Horizon 2020 research and innovation program under grant agreement No 883973.

Versioning and Authors

Version control

Revision	Date	Author	Organisation	Description
R-1	19.05.2024	Burak Dindar	KIT	Writing
R-1.1	02.06.2024	Hüseyin Kemâl Çakmak	KIT	Editing
R-1.2	08.07.2024	Daniel Alexander Müller	THU	Writing
R-1-3	15.01.2025	Burak Dindar	KIT	Writing
R-1.4	20.01.2025	Hüseyin Kemâl Çakmak	KIT	Editing
R-1.5	22.01.2025	Daniel Alexander Müller	THU	Editing
R-1.6	22.01.2025	Manuela McCulloch	THU	Editing
R-1-7	03.02.2025	Burak Dindar	KIT	Editing

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Executive Summary

Transitioning to a carbon-neutral power grid demands substantial changes, including the large-scale deployment of distributed energy resources (DERs), electric vehicles (EVs), and battery storage systems, collectively referred to as flexibility-providing units (FPUs). These advancements, primarily connected to low-voltage distribution grids, introduce challenges in grid management due to their complexity but simultaneously offer significant opportunities through their inherent flexibility. However, as these resources are predominantly connected to low-voltage distribution systems (DS), their effective integration necessitates seamless coordination between Transmission System Operators (TSOs) and Distribution System Operators (DSOs). Unfortunately, concerns over data privacy —particularly regarding grid models and sensitive operational data— present substantial barriers to achieving this coordination. Additionally, given the large number of FPUs and the grid complexity involved in analyses conducted over extensive areas, there is a need for methods with low computational complexity. These challenges significantly hinder the ability to fully utilize the flexibility of DSs. hindering the ability to fully utilize DSs' flexibility. In this deliverable, we introduce an innovative optimization framework aimed at leveraging DS flexibility while ensuring data confidentiality. To address the lack of access to DSO-provided grid models, a method is used for automated generation of low-voltage distribution system models using open-source data. This method enables the creation of detailed grid representations for specific regions, facilitating the inclusion of FPUs in real-world scenarios. The optimization framework incorporates linearized DS models using sensitivity matrices derived from multiple operating points. These sensitivity matrices, shared by DSOs with TSOs, abstract critical operational insights without revealing sensitive information such as network topology or configuration details. By embedding these matrices into a mixed-integer linear programming (MILP) formulation, the framework significantly reduces computational complexity while maintaining scalability and accuracy. This approach supports the inclusion of market-based constraints and a variety of objective functions, enabling the framework to adapt to diverse operational and market scenarios. The proposed method is extensively validated through benchmarking against traditional power flow techniques. Practical demonstrations showcase the framework's ability to model real-world DS operations, integrate FPUs into market-based systems, and provide TSOs with reliable estimates of available flexibility for congestion management. Numerical results confirm that the proposed solution achieves computational efficiency, maintains data confidentiality, and effectively utilizes DS flexibility to enhance the overall management of power systems. By eliminating the need for sensitive information exchange, the framework addresses privacy concerns while facilitating the secure and efficient integration of FPUs into energy markets. It enables TSOs to optimize grid-wide operations, leveraging the DSs' flexibility to improve grid reliability and economic efficiency. This approach not only supports the operational goals of a carbon-neutral power grid but also promotes stronger collaboration between TSOs and DSOs, setting the stage for a more resilient and sustainable energy future.

Kurzfassung

Der Übergang zu einem CO2-neutralen Stromnetz erfordert erhebliche Veränderungen, einschließlich der großflächigen Integration von dezentralen Energiequellen (DERs), Elektrofahrzeugen (EVs) und Batteriespeichersystemen, die zusammenfassend als Flexibilitätseinheiten (FPUs) bezeichnet werden. Diese Fortschritte, die hauptsächlich an Niederspannungsverteilungsnetze angeschlossen sind, stellen aufgrund ihrer Komplexität Herausforderungen für das Netzmanagement dar, bieten aber gleichzeitig durch ihre inhärente Flexibilität bedeutende Chancen. Da diese Ressourcen überwiegend mit Niederspannungsverteilungsnetzen (DS) verbunden sind, erfordert ihre effektive Integration jedoch eine nahtlose Koordination zwischen Übertragungsnetzbetreibern (TSOs) und Verteilnetzbetreibern (DSOs). Datenschutzbedenken – insbesondere im Hinblick auf Netzmodelle und sensible Betriebsdaten – stellen jedoch erhebliche Hürden für diese Koordination dar. Darüber hinaus besteht angesichts der großen Anzahl von FPUs und der Netzkomplexität bei Analysen, die über große Gebiete durchgeführt werden, ein Bedarf an Methoden mit geringer Rechenkomplexität. Diese Herausforderungen behindern die Fähigkeit, die Flexibilität von DSs voll auszunutzen, erheblich. In diesem Bericht stellen wir ein innovatives Optimierungsframework vor, das darauf abzielt, die Flexibilität von DS zu nutzen und gleichzeitig die Vertraulichkeit der Daten zu gewährleisten. Um den fehlenden Zugang zu von DSOs bereitgestellten Netzmodellen zu kompensieren, wird eine Methode zur automatisierten Erstellung von Niederspannungsverteilungsnetzmodellen mithilfe von Open-Source-Daten verwendet. Diese Methode ermöglicht die Erstellung detaillierter Netzrepräsentationen für spezifische Regionen und erleichtert die Einbindung von FPUs in realen Szenarien. Das Optimierungsframework integriert linearisierte DS-Modelle, die auf Sensitivitätsmatrizen basieren, die aus verschiedenen Betriebspunkten abgeleitet wurden. Diese Sensitivitätsmatrizen, die von den DSOs an die TSOs weitergegeben werden, abstrahieren wesentliche betriebliche Erkenntnisse, ohne sensible Informationen wie Netztopologie oder Konfigurationsdetails offenzulegen. Durch Einbettung dieser Matrizen in ein gemischt-ganzzahliges lineares Optimierungsproblem (MILP) wird die Rechenkomplexität erheblich reduziert, während Skalierbarkeit und Genauigkeit erhalten bleiben. Dieser Ansatz unterstützt die Einbindung marktbasierter Einschränkungen und verschiedener Zielfunktionen, sodass das Framework an unterschiedliche betriebliche und marktbezogene Szenarien angepasst werden kann. Die vorgeschlagene Methode wird umfassend durch Benchmarking gegenüber traditionellen Lastflussanalysen validiert. Praktische Demonstrationen zeigen die Fähigkeit des Frameworks, reale DS-Betriebe zu modellieren, FPUs in marktbasierten Systemen zu integrieren und TSOs zuverlässige Schätzungen der verfügbaren Flexibilität für das Engpassmanagement bereitzustellen. Numerische Ergebnisse bestätigen, dass die vorgeschlagene Lösung eine hohe Recheneffizienz erreicht, die Vertraulichkeit der Daten wahrt und die Flexibilität von DS effektiv nutzt, um das Gesamtmanagement von Stromnetzen zu verbessern. Durch den Verzicht auf den Austausch sensibler Informationen adressiert das Framework Datenschutzprobleme und ermöglicht gleichzeitig die sichere und effiziente Integration von FPUs in Energiemärkte. Es erlaubt TSOs, netzweite Betriebsabläufe zu optimieren, indem die Flexibilität von DS genutzt wird, um die Netzzuverlässigkeit und wirtschaftliche Effizienz zu steigern. Dieser Ansatz unterstützt nicht nur die Betriebsziele eines CO2-neutralen Stromnetzes, sondern fördert auch eine stärkere Zusammenarbeit zwischen TSOs und DSOs und schafft die Grundlage für eine widerstandsfähigere und nachhaltigere Energiezukunft.

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List of abbreviations

DA/RE	Datenaustausch/Redispatch
DERs	Distributed Energy Resources
DigIPlat	Digital Solutions for Interoperability of Flexibility Platforms
DS	Distribution System
DSO	Distribution System Operator
EVs	Electric Vehicles
FPUs	Flexibility Providing Unit
HV	High Voltage
LTDF	Loading Transfer Distribution Factor
LV	Low Voltage
MV	Medium Voltage
OSM	OpenStreetMap
PTDF	Power Transfer Distribution Factors
TS	Transmission System
TSO	Transmission System Operator
VTDF	Voltage Transfer Distribution Factors

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1 Introduction

The drive towards carbon neutrality in the power system is prompting a rapid transformation, characterized by a significant increase in distributed energy resources (DERs), predominantly fueled by renewable energy sources. While this transition offers numerous benefits, it also poses challenges in power system management. One of the primary challenges arises from the inherent variability of renewable energy sources. Fluctuations in wind or solar generation can lead to sudden changes in power production, complicating efforts to balance supply and demand within the power system [1]. For instance, in Germany, the surge in wind energy production in the northern regions coupled with increased consumption in the southern regions has resulted in cases where the energy transfer from north to south strains the grid, leading to line overloads [2]. This phenomenon not only impacts domestic grid operations but also has international consequences. For example, the congestion in transmission lines affects the transfer capacity from Germany to neighboring countries such as the Netherlands [3].

The imbalances stemming from the variability of renewable energy sources contribute to increased redispatch costs within the power system [4]. In Germany, these costs soared to 2.689 billion euros in 2022 [5]. To address this challenge, various initiatives and studies are underway to mitigate redispatch costs and optimize grid management. One such initiative is Redispatch 2.0, implemented in Germany, which mandates the participation of DERs with a capacity of 100 kW and above in redispatch activities [6]. Looking ahead, Redispatch 3.0 is poised to further evolve grid management practices by expanding participation to include consumers. With the entry into force of Redispatch 3.0, consumers will have the opportunity to actively engage in redispatch activities, contributing to grid stability and efficiency.

The evolving dynamics of the power system management landscape highlight significant shifts from traditional practices. Historically, network management was predominantly the responsibility of Transmission System Operators (TSOs). However, contemporary changes have expanded the role of other stakeholders within the energy sector, notably Distribution System Operators (DSOs) and DER companies, in network management. As DERs are predominantly integrated into the grid through the Distribution System (DS), the significance of DS has markedly increased [7, 8]. Consequently, there is a growing recognition of the need to enhance TSO-DSO interaction to ensure efficient and coordinated management of the power system. In response to this imperative, there is a proliferation of studies and initiatives aimed at augmenting TSO-DSO collaboration [9]. These endeavors seek to develop and implement various coordination schemes to optimize power system management. Various TSO-DSO coordination schemes [10] are given in Figure 1.

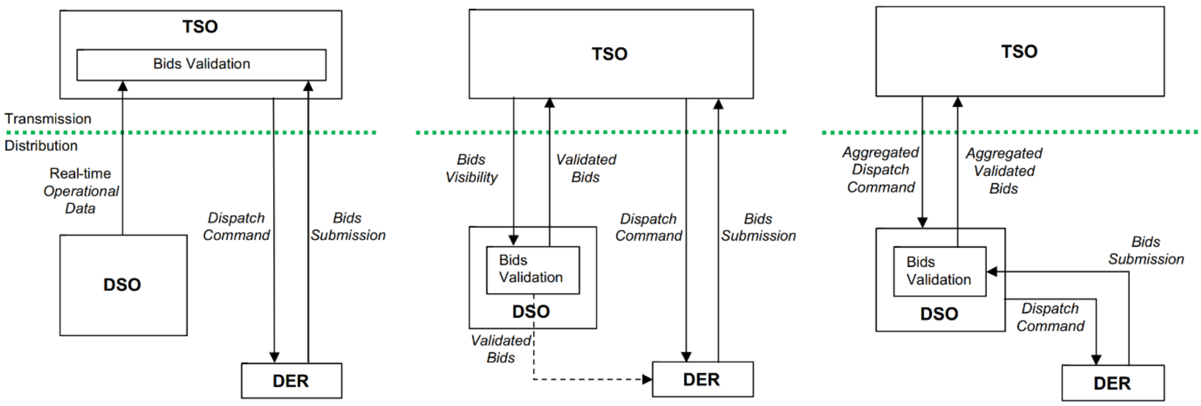

Figure 1 Various TSO-DSO coordination schemes: a) TSO-managed, b) TSO-DSO hybrid-managed, and c) DSO-managed models [10]

In the context of power system management, a critical consideration revolves around how to effectively integrate the flexibility of DSs through elements such as DERs, flexible loads, and batteries into overall grid operations. Various coordination schemes, as shown in Figure 1, have been proposed to address this challenge, encompassing both market-based and power system-based regulations. Market-based regulations aim to encourage and optimize the utilization of flexibility resources within the grid through market mechanisms. Power system-based regulations, on the other hand, focus on operational constraints and ensure the stability and reliability of the grid by considering factors such as line loadings and voltage limits, both in the transmission system (TS) and the DS.

The integration of DERs introduces new challenges, including network congestion and voltage issues arising from reverse power flow, particularly in the DS [11, 12]. These challenges necessitate coordinated control schemes between TSOs and DSOs to effectively manage the grid while ensuring compliance with operational limits and regulations. Unfortunately, implementing such coordination schemes is often complicated by various factors, including data privacy concerns, modeling challenges, computational limitations, and transparency issues. Conflicts may arise between TSOs and DSOs as they navigate these challenges and seek to balance competing interests and priorities [10].

Researchers have long been investigating effective strategies for managing flexibility within the DS. One prominent approach in this regard is the active-reactive power (PQ) capability chart approach [13]. This approach involves aggregating flexibility at the interface between the TS and the DS, enabling its utilization for various purposes such as minimizing operational costs and managing network congestion [14]. However, implementing the PQ capability chart approach poses several challenges. One significant challenge is the high computational complexity associated with accurately approximating a PQ chart. Furthermore, another key challenge lies in determining the cost associated with each point on the PQ chart, considering the presence of multiple DERs within the system [15].

Developing innovative solutions that address data privacy concerns of system operators while ensuring computational efficiency is indeed crucial for advancing power system management. However, one of the primary challenges hindering such advancements is the availability of accurate power system models. Accurate power system models that faithfully represent real networks are essential for conducting meaningful studies and developing effective solutions. Unfortunately, the sharing of detailed power system models is often restricted due to data privacy concerns [16]. As a result, many studies in literature are limited to utilizing standard test systems, which may not fully capture the complexities of real-world networks. To overcome this challenge, the Karlsruhe Institute of Technology (KIT) is undertaking detailed modeling efforts spanning from low-voltage (LV) to high-voltage (HV) within work package 4.3 of the project. These models, developed using open-source data, aim to accurately represent real networks and address the limitations posed by data privacy concerns. These detailed and comprehensive power system models are used in this work package.

In practice, the sharing of detailed power system models between TSOs and DSOs is often restricted due to various reasons, including data privacy concerns. Consequently, alternative approaches are pursued to facilitate collaboration and optimize grid management without necessitating the sharing of comprehensive network models. One such approach involves the use of simplified "light models" of the grid, as implemented on platforms like DA/RE [17]. In this work package, low-voltage DS is linearized using sensitivity matrices to address above-mentioned problems. The linearized model, which captures key system dynamics in a simplified form, is then utilized for market-based operations. In order to minimize the approximation error of the linearization, a piecewise approach to linearization is introduced.

Using the sensitivity-based approach, a mixed-integer linear program (MILP) is performed for the local flexibility activation within the DS, enabling effective utilization of flexibility resources while preserving data privacy. This approach enables market-based operations to be conducted with low computational complexity, circumventing the need for detailed network models. By leveraging these simplified models and sensitivity-based approaches, stakeholders can effectively harness flexibility resources within the DS while adhering to operational limits and mitigating local bottlenecks.

2 Workflow of the Work Package

In general, DS flexibility can serve various purposes in power grid management. Within this work package, we focus specifically on leveraging DS flexibility for balancing energy, which is crucial for stabilizing the grid in cases of imbalances between generation and consumption and enables participation of FPUs in markets via pooling. This process is carried out while ensuring compliance with network constraints, such as line loading and voltage limits. To achieve this, we aim to establish framework conditions that enable the effective and interoperable utilization of flexibility, thereby enhancing both economic efficiency and system stability. The workflow of this work package is depicted in Figure 2.

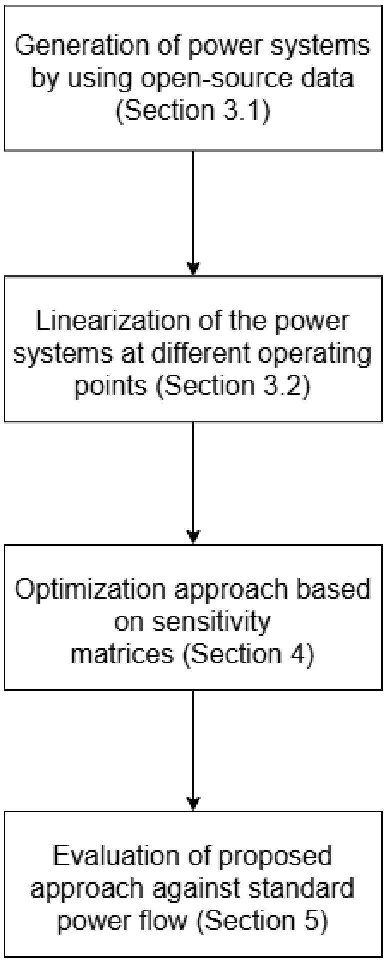

Figure 2 Workflow of the work package

Here, the first step is to create grid models for conducting the analyses. It is essential that these models accurately represent real-world grid conditions to facilitate the flexible execution of futuristic analyses. However, due to the importance of data privacy, these models cannot be shared by system operators. Hence, within the framework of work package 4.3, appropriate grid models were developed employing open-source data (For more detailed insights on the generation of these models, please refer to deliverable 4.3). With these models, researchers and stakeholders can effortlessly explore various scenarios.

Following that, research will be conducted taking into account the data privacy concerns between TSOs and DSOs. Using a sensitivity-based approach, the grid models will be piecewise linearized through a first-order Taylor expansion. This process utilizes sensitivity matrices and base values, such as voltage magnitudes and element loadings, calculated at various selected operating points. This methodology enables an accurate approximation of grid behavior across a wide range of operating conditions. This also enables the sharing of sensitivity matrices with relevant partners instead of sharing complete grid models containing sensitive data. Thus, this approach contributes to ensuring data privacy while facilitating analyses at the TSO-DSO interface.

The linearized model is subsequently integrated into a mixed-integer linear programming (MILP) framework for flexibility provisioning, enabling computationally efficient solutions even as grid complexity increases. This approach is designed to accommodate diverse market scenarios and objective functions, ensuring the effective utilization of DS flexibility while maintaining data privacy measures. By safeguarding sensitive information, this method facilitates the exploration of effective grid management strategies without compromising stakeholder confidentiality.

Finally, the proposed optimization method will be compared to standard power flow using various metrics to evaluate its effectiveness. This comparative analysis will serve to validate the efficiency of the proposed approach in addressing grid constraints and optimizing power system operations.

3 Piecewise Linearization of the Distribution Grid for Data Privacy

The increasing presence of DERs is significantly altering the grid structure, causing the network to undergo frequent recalculations due to the fluctuating nature of these DERs. This variability necessitates the adoption of computationally efficient methods to ensure the stability and reliability of the power system [18]. One of the most important techniques used in power grid security assessments is the linear sensitivity approach [19]. This approach involves linearizing the system around an operating point and deriving various sensitivity matrices using the power system's Jacobian matrix. Before applying the proposed method, a detailed examination of the distribution grid on which the analysis will be performed is necessary to select the linearization points appropriately. This step is crucial to ensure the accuracy and reliability of the results, as the choice of linearization points directly affects the performance of the flexibility provisioning process. Properly selected linearization points minimize the approximation error and allow for a more accurate representation of the system's behavior under various operating conditions.

3.1 Bergwald Low Voltage Grid Model

Although, as demonstrated in [16], urban low voltage grids with up to 45,000 buildings can be created, in the context of this work package, we focus on the Bergwald LV distribution grid, which was created in work package 4.3 using open-source data (See deliverable 4.3 for details on the generation of this model). The generated Bergwald model is shown in Figure 3.

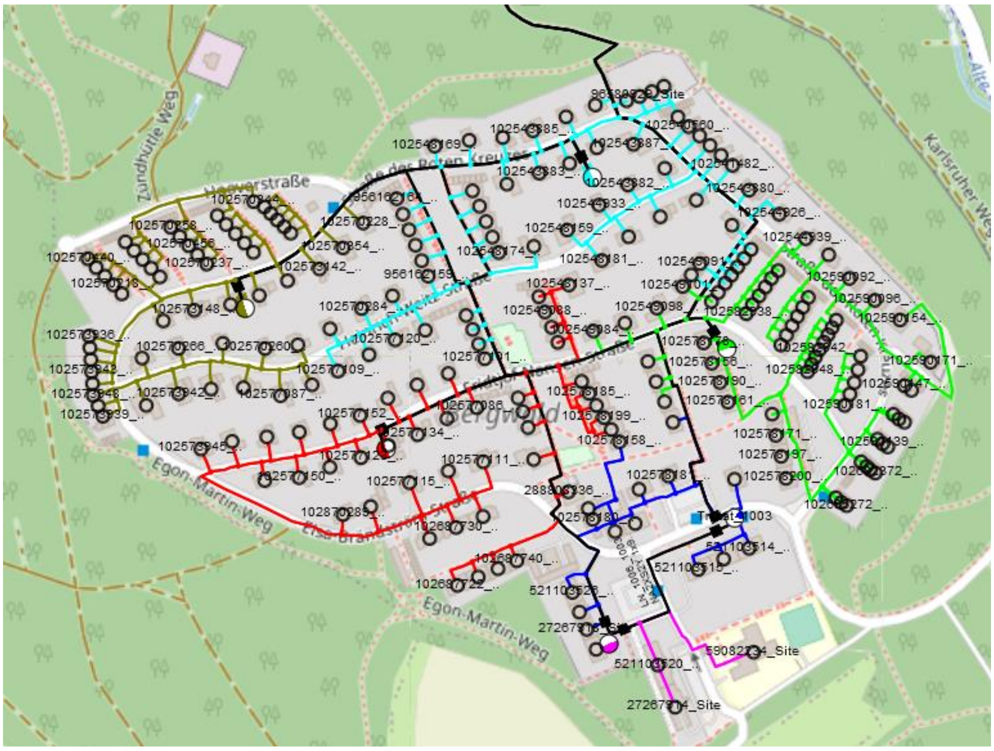

Figure 3 Generated Bergwald grid model

The Bergwald model, which encompasses a residential area, has been developed to provide a comprehensive representation of the local distribution network. This area includes a total of 241 buildings, comprising a variety of residential structures such as single houses, duplexes, townhouses, and apartment towers, as well as non-residential facilities like a school, a community center, and several shops. In a future scenario envisioned for this study, it is assumed that all these buildings have the potential to deliver flexibility services. These flexibilities are essential for effective network management, particularly in balancing supply and demand and maintaining grid stability.

The incorporation of flexibility from DERs into network management practices is crucial for enhancing the efficiency and reliability of the power system. However, leveraging this flexibility is challenging due to significant data privacy concerns. DSOs are often hesitant to share detailed information about their networks related sensitive data such as grid topology and customer load demands.

To address these privacy concerns while still enabling the use of flexibility in network management, this work package proposes the use of sensitivity-based approaches. In the Bergwald LV distribution grid, these sensitivity-based methods will be employed to facilitate market-based operations and network management. The flexibility obtained from buildings in the area can be used for different purposes. By sharing sensitivity matrices instead of detailed network data, DSOs can maintain the privacy of their sensitive information while still participating in collaborative efforts to enhance grid management.

3.2 Piecewise Linear Approximation

The linear sensitivity approach is primarily employed to understand how a change in one part of the system affects other parts. The most commonly used sensitivity matrices in this context are Power Transfer Distribution Factors (PTDF), which typically assess the impact of power injections at a specific bus on power flows across transmission lines [20]. Similarly, to approximate the variations in voltage magnitudes and branch loadings resulting from power injections at a given bus, distribution factors specific to voltage magnitudes (VTDF) and branch loadings (LTDF) can be defined. These factors provide a linear approximation of how changes in active power injections affect voltage and loading in the system, thereby enabling computationally efficient analysis of the grid's behavior. These sensitivity matrices are critical tools in several areas of network management, including transmission congestion management [21] and redispatch [22].

In the past, sensitivity-based approaches were predominantly applied to the transmission system. However, in recent years, researchers have started to employ these approaches in the distribution system as well [23, 24]. The increasing number of DERs in the distribution system and the potential flexibility they offer for network management elements have contributed to this trend [25].

Flexibility provisioning involves adapting active power generation or consumption based on the characteristics of FPUs. This adaptation is quantified as $\Delta\boldsymbol{P}$, which modifies the active power injections at n nodes from their initial values $\boldsymbol{P}$ to $\boldsymbol{P} + \Delta\boldsymbol{P}$. These adjustments affect system parameters, resulting in changes to the nodal voltages $\Delta\boldsymbol{V}$ across v nodes and the branch loadings $\Delta\boldsymbol{L}$ over l branches, such as transformers and power lines. To ensure the system remains within operational limits during this process, it is critical to avoid exceeding permissible voltage and loading levels. The relationships governing these interactions are described as:

$$F_V : \mathbb{R}^n \rightarrow \mathbb{R}^v, (\boldsymbol{P} + \Delta\boldsymbol{P}) \rightarrow (\boldsymbol{V} + \Delta\boldsymbol{V}), \quad (1)$$

$$F_L : \mathbb{R}^n \rightarrow \mathbb{R}^l, (\boldsymbol{P} + \Delta\boldsymbol{P}) \rightarrow (\boldsymbol{L} + \Delta\boldsymbol{L}), \quad (2)$$

Here, $\boldsymbol{V}$ and $\boldsymbol{L}$ represent the system's initial nodal voltage magnitudes and branch loadings, respectively. The functions F_V and F_L map the total power injections to the resulting changes in voltages and loadings, with $\Delta\boldsymbol{V}$ and $\Delta\boldsymbol{L}$ emerging from the combined effects of $\boldsymbol{P}, \boldsymbol{V}, \boldsymbol{L}$ and $\Delta\boldsymbol{P}$. Owing to the nonlinear characteristics of power flow equations, these mappings are inherently nonlinear. In low-voltage grids, the diversity and high number of FPUs further amplify system complexity, making it essential to adopt computational approaches that address these challenges efficiently.

To approximate the mapping functions, we can use the VTDF and LTDF. By using these factors, the $\Delta\boldsymbol{V}$ and $\Delta\boldsymbol{L}$ can be defined as follows:

$$\Delta\boldsymbol{V} = \boldsymbol{VTDF}\Delta\boldsymbol{P}\ , \quad (3)$$

$$\Delta\boldsymbol{L} = \boldsymbol{LTDF}\Delta\boldsymbol{P}\ , \quad (4)$$

Given that $\Delta\boldsymbol{V}$ and $\Delta\boldsymbol{L}$ at the linearization point are already known, these equations facilitate the efficient approximation of F_V and F_L using linear sensitivity factors. This approach allows for computationally practical solutions, even in the context of the significant complexity associated with low-voltage distribution grids. Thus, these sensitivity values serve as a basis for estimating the updated network conditions during the flexibility provisioning process, as outlined below:

$$\widetilde{\boldsymbol{V}} = \boldsymbol{V} + \boldsymbol{VTDF}\Delta\boldsymbol{P}\ , \quad (5)$$

$$\widetilde{\boldsymbol{L}} = \boldsymbol{L} + \boldsymbol{LTDF}\Delta\boldsymbol{P}\ . \quad (6)$$

Here, $\widetilde{\boldsymbol{V}}$ and $\widetilde{\boldsymbol{L}}$ denote the updated nodal voltage magnitudes and branch loadings, respectively, following the active power adjustment $\Delta\boldsymbol{P}$. Unlike conventional methods in the literature that derive sensitivity matrices using DC power flow, this study employs AC power flow to compute these values. Furthermore, the formulation explicitly accounts only for variations in active power $\Delta\boldsymbol{P}$ when determining $\Delta\boldsymbol{V}$ and $\Delta\boldsymbol{L}$. Effects arising from other factors, such as reactive power changes or voltage regulation mechanisms, are excluded in this approximation. It is also essential to emphasize that the VTDF and LTDF values are computed based on a specific operational condition, commonly referred to as the base scenario. Consequently, any significant deviations, such as those associated with varying day types or time frames, necessitate recalculating these sensitivity values to reflect the updated system state.

It is well-established that linearization yields higher accuracy when the system operates close to the linearization point. While small deviations around this point produce minimal errors, the accuracy declines substantially as the system's operating condition moves further away. To address this limitation and ensure precise flexibility provisioning across a wider operational range, a piecewise linear approximation is utilized. This method involves linearizing the system at m distinct operating points over a specified time period. Each of these operating points is associated with a tuple $\boldsymbol{P}_i, \boldsymbol{V}_i, \boldsymbol{L}_i, \boldsymbol{VTDF}_i, \boldsymbol{LTDF}_i$,, which encapsulates the parameters needed for the respective linear approximations. The set of all operating points is represented by the index set $\mathcal{I} := \{0, 1, \dots, m-1\}$, where $i \in \mathcal{I}$. As a result, the expressions for the updated nodal voltages and branch loadings can be extended to incorporate multiple operating points as follows:

$$G_{V,i}(\Delta\boldsymbol{P}_i) = \quad \widetilde{\boldsymbol{V}}_i = \boldsymbol{V}_i + \boldsymbol{VTDF}_i\, \Delta\boldsymbol{P}_i \quad i \in \mathcal{I}, \quad (7)$$

$$G_{L,i}(\Delta \boldsymbol{P}_i) = \quad \tilde{\boldsymbol{L}}_i = \boldsymbol{L}_i + \boldsymbol{LTDF}_i\, \Delta \boldsymbol{P}_i \quad i \in \mathcal{I}. \tag{8}$$

In this context, $\widetilde{\boldsymbol{V}}_i$ and $\tilde{\boldsymbol{L}}_i$ denote the updated nodal voltage magnitudes and branch loadings, respectively, computed for the i-th operational point following the active power adjustment $\Delta \boldsymbol{P}_i$. The approximation functions, $G_{V,i}(\Delta \boldsymbol{P}_i)$ and $G_{L,i}(\Delta \boldsymbol{P}_i)$, are used to estimate the nodal voltage magnitudes and branch loadings for each operational point.

To ensure a well-defined piecewise linear approximation, each approximation must be valid within a specific region where it remains sufficiently accurate. Consequently, the input space $\mathbb{R}^n$ is subdivided into convex polygons using a Voronoi tessellation. For each linearization point i, the power injection vector $\boldsymbol{P_i}$ serves as the center of a convex polygon $\mathcal{P}_i$ which is defined by the following minimum distance condition:

$$\mathcal{P}_i = \{\boldsymbol{X} \in \mathbb{R}^n \mid d(\boldsymbol{X}, \boldsymbol{P}_i) < d(\boldsymbol{X}, \boldsymbol{P}_j), \qquad \forall_{i,j} \in \mathcal{I}, i \neq j\}, \tag{9}$$

where $d(\cdot, \cdot)$ is the Euclidean distance. This approach results in a partition of the input space into non-overlapping, adjacent regions. Within each convex polygon $\mathcal{P}_i$, the non-linear network functions F_V and F_L can be approximated linearly by $G_{V,i}(\Delta \boldsymbol{P_i})$ and $G_{L,i}(\Delta \boldsymbol{P}_i)$, providing that the updated power injection $\boldsymbol{P}_i + \Delta \boldsymbol{P}_i$ remains within $\mathcal{P}_i$. A schematic representation of the partitioning process and the update $\boldsymbol{P}_i + \Delta \boldsymbol{P}_i$ is shown in Figure 4. The convex polygon boundaries $\mathcal{P}_i$ are indicated in blue, and the update lies inside $\mathcal{P}_2$, implying that $G_{V,2}(\Delta \boldsymbol{P}_2)$ and $G_{L,2}(\Delta \boldsymbol{P}_2)$, provide the appropriate approximations for this region.

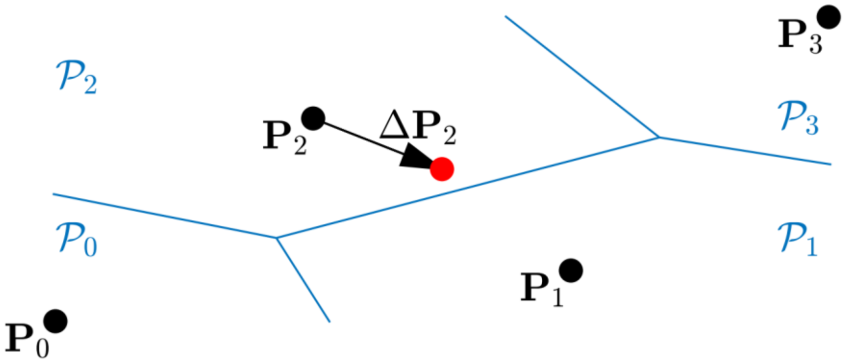

Figure 4 Schematic representation of the tessellated input space with non-boundary violating update

This approach allows the selection of a linear approximation to be integrated into an optimization problem, where the objective is to minimize the distance between the update and the linearization point. By doing so, the approximation error remains small.

The next section will provide a detailed explanation of how these sensitivity matrices will be used to implement market-based methods, demonstrating the practical applications of this approach using the example of the Bergwald LV distribution grid.

4 Optimization Approach for Flexibility Provisioning

The polygon $\mathcal{P}_i$, which is introduced in the previous section, is defined using the nonlinear Euclidean distance, making it incompatible with linear programming. To address this issue, a linear auxiliary function is introduced to verify whether $\boldsymbol{P}_i + \Delta \boldsymbol{P}_i \in \mathcal{P}_i$. In general, an r-dimensional hyperplane can be described by $\boldsymbol{N}^T(\boldsymbol{X} - \boldsymbol{A}) = 0 \ \forall \boldsymbol{X} \in \mathbb{R}^r$, where $\boldsymbol{A}$ represents a point on the plane. When applied to the domain of power injections, $\boldsymbol{A}$ is chosen as the midpoint between two linearization points, while the normal vector $\boldsymbol{N}$ is defined as the vector connecting these points. Based on this setup, the auxiliary function is formulated as follows:

$$H_{i,j}(\Delta\boldsymbol{P}_i) = (\boldsymbol{P}_i - \boldsymbol{P}_j)^T \left(\boldsymbol{P}_i + \Delta\boldsymbol{P}_i - \frac{\boldsymbol{P}_i + \boldsymbol{P}_j}{2}\right). \tag{10}$$

As a result, $\boldsymbol{P}_i + \Delta\boldsymbol{P}_i \in \mathcal{P}_i$ if the condition $H_{i,j}(\Delta\boldsymbol{P}_i) \geq 0 \; \forall j \in \mathcal{I}, i \neq j$ is satisfied. In the context of flexibility provisioning, the linearization point $\boldsymbol{P}_i$ can be expressed as the sum of fixed, market-independent power injections $\boldsymbol{P}_{Fix,i}$ and the power injections arising from activated flexibilities $\boldsymbol{P}_{Flex,i}$:

$$\boldsymbol{P}_i = \boldsymbol{P}_{Fix,i} + \boldsymbol{P}_{Flex,i}. \tag{11}$$

When the power adjustment $\Delta\boldsymbol{P}_i$ is added to the previous equality, the term $\boldsymbol{P}_{Flex,i} + \Delta\boldsymbol{P}_i$ reflects the updated power injections associated with activated flexibilities. Assuming the market provides a bid constellation with costs $\boldsymbol{c} \in \mathbb{R}^n$, corresponding volumes $\boldsymbol{P}_M \in \mathbb{R}^n$, and specifies a total balancing power requirement of $P_E \in \mathbb{R}^n$, (derived from balancing energy BE), our approach determines whether the bids are fully activated, partially activated, or excluded. Consequently, the adjusted dispatched bids are limited like as follows:

$$\boldsymbol{P}_{Flex,i} + \Delta\boldsymbol{P}_i \;\geq\; \boldsymbol{P}_{LB} \coloneqq \min(\boldsymbol{0}, \boldsymbol{P}_M), \tag{12}$$

$$\boldsymbol{P}_{Flex,i} + \Delta\boldsymbol{P}_i \;\leq\; \boldsymbol{P}_{UB} \coloneqq \max(\boldsymbol{0}, \boldsymbol{P}_M), \tag{13}$$

The operators $\min$ and $\max$ are applied elementwise, enabling the lower and upper power injection bounds $\boldsymbol{P}_{LB}$ and $\boldsymbol{P}_{UB}$ to be derived from positive and negative market volumes $\boldsymbol{P}_M$.

The optimization process seeks to construct a minimum-cost bid configuration while ensuring that grid constraints are satisfied. Specifically, the updated branch loadings $\tilde{\boldsymbol{L}}$ must lie within the range $[\boldsymbol{L}_{LB}, \boldsymbol{L}_{UB}]$, and the voltage magnitudes $\tilde{\boldsymbol{V}}$ must remain within $[\boldsymbol{V}_{LB}, \boldsymbol{V}_{UB}]$. Here, the subscripts LB and UB represent the respective lower and upper bounds.

To achieve this, a mixed-integer linear programming approach is employed to optimize the power adjustments $\Delta\boldsymbol{P}_i$. Binary decision variables $b_i \in \{0,1\}$ are introduced to select the appropriate approximation:

$$\min_{\Delta\boldsymbol{P}_i, b_i, \forall i \in \mathcal{I}} \sum_{i \in \mathcal{I}} \boldsymbol{c}^T(\boldsymbol{P}_{Flex,i} + \Delta\boldsymbol{P}_i) b_i \tag{14a}$$

$$s.t$$

$$\Delta\boldsymbol{P}_i \geq (\boldsymbol{P}_{LB} - \boldsymbol{P}_{Flex,i}) b_i, \qquad \forall i \in \mathcal{I}, \tag{14b}$$

$$\Delta\boldsymbol{P}_i \leq (\boldsymbol{P}_{UB} - \boldsymbol{P}_{Flex,i}) b_i, \qquad \forall i \in \mathcal{I}, \tag{14c}$$

$$G_{L,i}(\Delta\boldsymbol{P}_i) \geq \boldsymbol{L}_{LB} b_i + \boldsymbol{L}_i(1 - b_i), \quad \forall i \in \mathcal{I}, \tag{14d}$$

$$G_{L,i}(\Delta\boldsymbol{P}_i) \leq \boldsymbol{L}_{UB} b_i + \boldsymbol{L}_i(1 - b_i), \quad \forall i \in \mathcal{I}, \tag{14e}$$

$$G_{V,i}(\Delta\boldsymbol{P}_i) \geq \boldsymbol{V}_{LB} b_i + \boldsymbol{V}_i(1 - b_i), \quad \forall i \in \mathcal{I}, \tag{14f}$$

$$G_{V,i}(\Delta\boldsymbol{P}_i) \leq \boldsymbol{V}_{UB} b_i + \boldsymbol{V}_i(1 - b_i), \quad \forall i \in \mathcal{I}, \tag{14g}$$

$$H_{i,j}(\Delta\boldsymbol{P}_i) b_i \geq 0, \qquad \forall i,j \in \mathcal{I}, \quad i \neq j, \tag{14h}$$

$$\sum_{i \in \mathcal{I}} b_i = 1, \tag{14i}$$

$$\sum_{i\,\in\,\mathcal{I}} \left(\boldsymbol{P}_{Flex,i} + \Delta\boldsymbol{P}_i\right) = P_E\ . \tag{14j}$$

The objective function in (14a) minimizes the total cost associated with the dispatched bids after incorporating a power adjustment. Equation (14i) enforces that only one decision variable is active (i.e., equal to 1) at a time. The appropriate approximation is selected using (14h). Additionally, constraints (14b) and (14c) guarantee that (12) and (13) hold.

To prevent congestion, equations (14d) - (14g) restrict the power adjustments such that no violations occur within the grid. Lastly, (14j) guarantees that the required volume of balancing energy is delivered. Together, these formulations create a robust optimization framework for managing flexibility provisioning while avoiding congestion, as demonstrated in the subsequent section.

5 Evaluation

After applying the piecewise linearization of the grid model using sensitivity matrices and completing the optimization process, it becomes essential to evaluate the performance of the entire approach. As is well known, linearization inherently introduces some errors. Assessing whether these errors could pose challenges to the operation of the distribution grid is critical.

To this end, the linearization-based calculations should be rigorously compared against the standard power flow results. This comparison ensures that any discrepancies are quantified and that the proposed method's accuracy remains within acceptable limits for practical application. Evaluating such errors is crucial for validating the reliability and feasibility of the proposed framework in real-world grid operations.

Using all available flexibility simultaneously in a distribution network can lead to congestion, potentially overloading certain lines and jeopardizing the network's reliability. To prevent this, it is necessary to deploy flexibility in a cost-effective and strategically optimized manner. This requires a robust optimization approach that ensures the efficient utilization of flexibility without overloading the network. For instance, in the Bergwald grid model where the analyses are conducted, this issue is evident. As shown in Figure 5, employing all available flexibility results in congestion on certain lines, marked in red.

Figure 5 All flexibility active, red indicating congestions

This highlights the importance of implementing an optimization framework that carefully selects and regulates the use of flexibility to balance cost-efficiency and grid stability, avoiding such congestion scenarios. The optimization approach detailed in the preceding sections is applied to the Bergwald grid model.

The analysis considers a single time frame during which the TSO requests 1.8 MW of flexibility from the DS. Despite this focus, the proposed methodology is adaptable and can be extended to accommodate different day types and time frames. For this specific scenario, three distinct linearization points are chosen to assess the method's performance over a broad range of operational conditions: one where all offered bids are fully activated, a second where half of them are activated, and a third where none are activated. The voltage limits are set as $\boldsymbol{V}_{LB} =$

0.95 p.u. and $\boldsymbol{V}_{UB} = 1.05$ p.u., while the branch loading constraints are defined as $\boldsymbol{L}_{LB} = -100\%$ and $\boldsymbol{L}_{UB} = 100\%$. Notably, the negative lower bound ensures that the load flow direction can be reversed, as reflected in (14). The resulting grid status after optimization is presented in Figure 6, illustrating the successful mitigation of congestion while maintaining efficient and secure operation of the distribution network.

Figure 6 Grid status after the optimization process

By ensuring that only the appropriate amount of flexibility is utilized, the method prevents overloading of network components, thereby maintaining the grid's safe, stable, and efficient operation. This demonstrates the effectiveness of the proposed framework in leveraging flexibility while avoiding adverse impacts on the grid infrastructure. It is important to acknowledge that these results are based on the linearized method, which inherently introduces some approximation errors. Therefore, to validate the accuracy and reliability of the proposed approach, it is essential to compare the outcomes with those obtained using the standard power flow. This comparison will help assess the practical applicability of the optimization framework and ensure its alignment with real-world grid operation.

To facilitate this comparison, the flexibility usage obtained from the optimization process is used as input in the standard power flow analysis. The power flow is then solved using these values, and key grid parameters such as line and transformer loadings, as well as voltage magnitude values at the busbars, are calculated. These results are then compared with the corresponding values obtained from the optimization framework.

To compare the two methods effectively and appropriately, various metrics need to be used. Here, we select the mean absolute error (MAE) and root mean square error (RMSE) metrics for the comparisons, determined as follows:

$$\mathrm{MAE} = \frac{1}{n}\sum_{i=1}^{n}\left|x_i^{opt} - x_i^{pf}\right| \tag{15}$$

$$\mathrm{RMSE} = \sqrt{\frac{1}{n}\sum_{i=1}^{n}\left(x_i^{opt} - x_i^{pf}\right)^2} \tag{16}$$

where x_i^{opt}represents the result from the optimization method, x_i^{pf} is the corresponding value from the power flow, and n is the total number of data points.

As indicated previously, these comparisons are conducted for the voltage magnitudes at the busbars as well as the loadings of lines and transformers. The metrics used for the evaluation are summarized in Table 1.

Table 1 Comparision of the optimization framework and standard power flow

Metrics	Voltages (p. u.)	Loadings (%)
MAE	$2.3\ x\ 10^{-5}$	$6.1\ x\ 10^{-3}$
RMSE	$2.6\ x\ 10^{-5}$	$9.8\ x\ 10^{-3}$

It can be observed that all metrics are close to zero, indicating the high accuracy of the optimization approach for the selected case. This demonstrates the effectiveness of the proposed method in closely approximating the results of the standard power flow, validating its reliability and practical applicability.

Following the numerical analysis, a visual examination is conducted to focus on busbars prone to voltage issues and lines or transformers that tend to experience overloading elements deemed critical for detailed assessment. Figures 7 and 8 illustrate the voltage magnitudes and loading values of these critical elements, respectively.

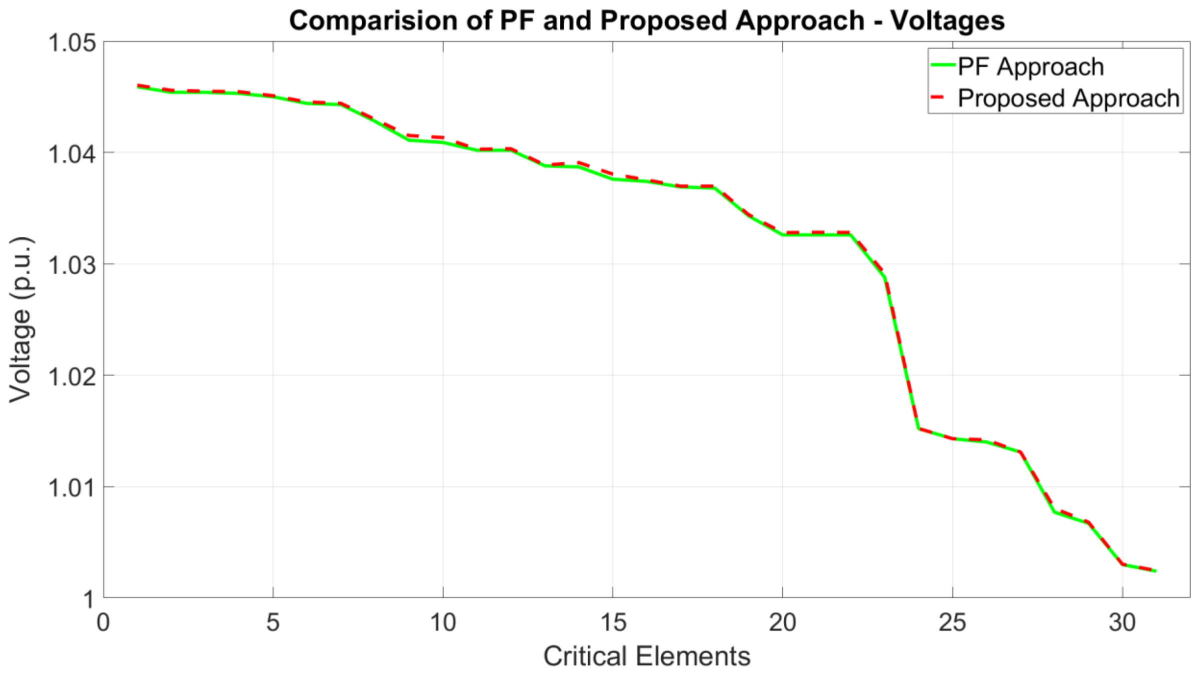

Figure 7 Comparison of PF and the proposed approach for voltage magnitudes

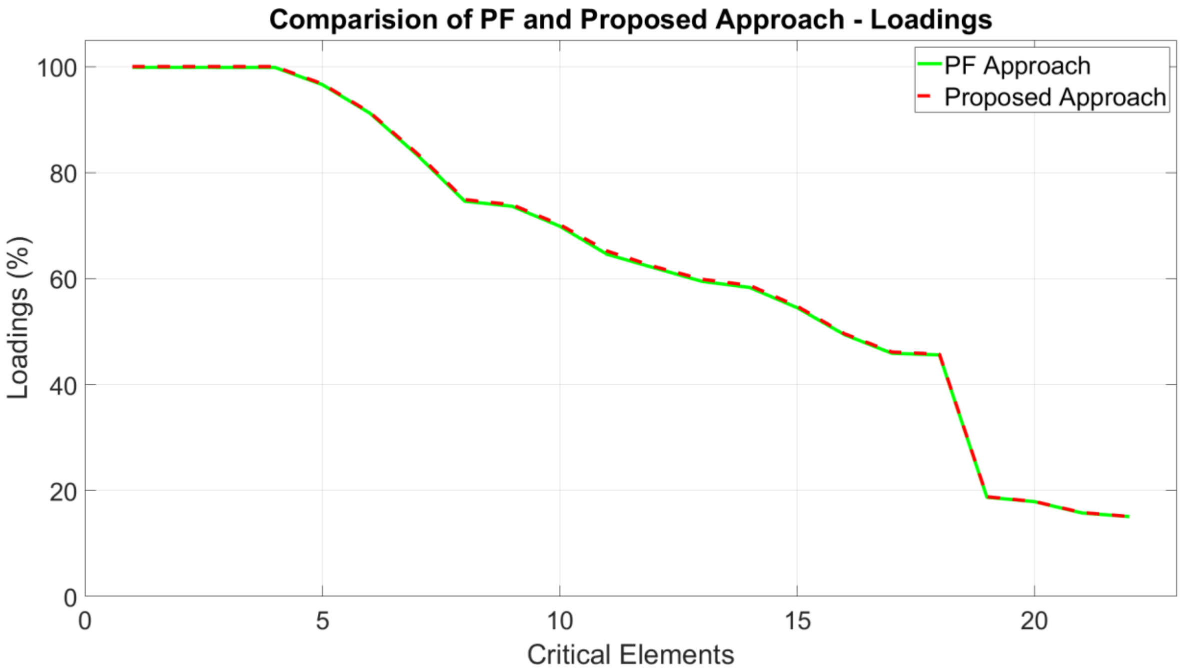

Figure 8 Comparison of PF and the proposed approach for loadings

As illustrated in the figures, the piecewise linearization-based optimization approach yields result comparable to those of the standard power flow, all while preserving data privacy. This demonstrates the effectiveness and practicality of the proposed method for use in grid operations.

6 Conclusion

This deliverable presents an innovative optimization framework aimed at enhancing interoperability and addressing the critical issue of data privacy between Transmission System Operators (TSOs) and Distribution System Operators (DSOs). The proposed approach employs piecewise linearization of distribution system (DS) models through sensitivity matrices, which are computed at various operating points. These matrices, along with their corresponding base values, are shared with the TSO, enabling the exchange of essential operational insights without compromising sensitive information such as network topology or other confidential details. The TSO subsequently incorporates these sensitivity matrices into a mixed-integer linear programming (MILP) framework, allowing the efficient utilization of DS flexibility for diverse operational and market-based applications.

The effectiveness of the proposed methodology is demonstrated through benchmarking against standard power flow techniques. The results reveal that the approach not only meets the desired operational objectives but does so while ensuring strict adherence to data confidentiality principles. By abstracting DS behavior into linearized constraints, the framework effectively reduces computational complexity, enabling scalable and efficient problem-solving even in scenarios involving a large number of components connected to low-voltage grids. This encourages the use of this method in modern power systems where the integration of numerous distributed energy resources (DERs), electric vehicles (EVs) and other flexibility-providing units (FPUs) is becoming increasingly prevalent.

One of the major outcomes of the proposed method is its ability to facilitate the seamless integration of FPUs into energy markets while maintaining the integrity of sensitive DSO data. By accurately quantifying the flexibility available from distribution systems, TSOs can effectively leverage this resource for congestion management, ensuring the smooth operation of the entire power system. This contributes to enhanced efficiency, reliability, and economic viability in grid operations, addressing some of the key challenges associated with the transition to a carbon-neutral energy system.

Despite the promising findings, certain enhancements are necessary to enable the practical application of the proposed method in real-world scenarios. These include utilizing more comprehensive grid models that incorporate dynamic elements, such as the control strategies of FPUs and the operational behavior of transformer tap changers. Integrating these factors would improve the robustness and applicability of the method, ensuring its effectiveness under more realistic and dynamic grid conditions. Also, the current optimization approach assumes that bids can be regulated down to very small portions. However, this is in contradiction to technical feasibility and the regulatory framework, such as the minimum bid size.

Overall, this work represents a significant step toward achieving secure, efficient, and collaborative grid management in the context of modern, decentralized power systems. The proposed framework not only addresses current challenges but also lays the groundwork for future advancements in leveraging distribution system flexibility, fostering closer coordination between TSOs and DSOs, and advancing the operational goals of a sustainable, resilient energy grid.

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