REGULATION (EU) 2023/1804

ON THE DEPLOYMENT OF ALTERNATIVE FUELS INFRASTRUCTURE, AND REPEALING DIRECTIVE 2014/94/EU

August 2024

Report Reference 10/2024

Any correspondence for this document should be sent to the Cyprus Energy Regulatory Authority.

ASSESSMENT REPORT IN ACCORDANCE WITH ARTICLES 15(3) AND 15(4) OF REGULATION (EU) 2023/1804 ON THE DEPLOYMENT OF ALTERNATIVE FUELS INFRASTRUCTURE

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1. INTRODUCTION

Directive 2014/94/EU of the European Parliament and of the Council laid down a framework for the deployment of alternative fuels infrastructure. The Commission Communication of 9 December 2020 entitled 'Sustainable and Smart Mobility Strategy – putting European transport on track for the future' points to the uneven development of recharging and refuelling infrastructure across the Union and the lack of interoperability and user friendliness. It notes that the absence of a clear common methodology for setting targets and adopting measures under the national policy frameworks required by Directive 2014/94/EU has led to a situation whereby the level of ambition in target setting and supporting policies differs greatly among Member States. Those differences have hindered the establishment of a comprehensive and complete network of alternative fuels infrastructure across the Union.

Regulation (EU) 2023/1804 "on the deployment of alternative fuels infrastructure" establishes mandatory national targets leading to the deployment of sufficient alternative fuels infrastructure in the Union for road vehicles, trains, vessels and stationary aircraft. It lays down common technical specifications and requirements on user information, data provision and payment requirements for alternative fuels infrastructure. The Regulation also establishes rules for the national policy frameworks referred to in Article 14 to be adopted by the Member States, including rules for the deployment of alternative fuels infrastructure in areas where no mandatory Union-wide targets are set and for reporting on the deployment of such infrastructure. Moreover, it establishes a reporting mechanism to encourage cooperation and ensures robust tracking of progress. The reporting mechanism shall take the form of a structured, transparent and iterative process taking place between the Commission and Member States for the purpose of finalising the national policy frameworks, taking into account existing local and regional strategies for the deployment of alternative fuels infrastructure, and their subsequent implementation and corresponding Commission action to support the coherent and more rapid deployment of alternative fuels infrastructure in the Member States.

2. THE ROLE OF THE CYPRUS ENERGY REGULATORY AUTHORITY

The Cyprus Energy Regulatory Authority (CERA) has been designated as the competent authority for the preparation of the National Assessment Report in accordance with the Articles 15(3) and (4) of the Regulation (EU) 2023/1804 "on the deployment of alternative fuels infrastructure". More specifically, the Passages (3) and (4) of Article 15 "National Reporting" provision:

- (3) By 30 June 2024 and every three years thereafter, Member States shall assess how the deployment and operation of recharging points could enable electric vehicles to further contribute to the flexibility of the energy system, including their participation in the balancing market, and to the further absorption of renewable electricity. That assessment shall take into account all types of recharging points, including those offering smart and bi-directional recharging, and all power outputs, whether public or private, and provide recommendations in terms of type of recharging point, supporting technology and geographical distribution in order to facilitate the ability of users to integrate their electric vehicles in the system. That assessment shall identify appropriate measures to be implemented in order to meet the requirements set out in this Regulation including those to ensure the consistency of infrastructure planning with the corresponding grid planning. That assessment shall take into account input from all stakeholders and shall be made publicly available. Each Member State may request its regulatory authority to carry out that assessment. On the basis of the results of the assessment, Member States shall, if necessary, take appropriate measures for the deployment of additional recharging points and include those measures in the national progress reports referred to in paragraph 1 of this Article. The assessment and measures shall be taken into account by the system operators in the network development plans referred to in Article 32(3) and Article 51 of Directive (EU) 2019/944.

- (4) On the basis of input from transmission system operators and distribution system operators, the regulatory authority of each Member State shall assess, by 30 June 2024 and every three years thereafter, the potential contribution of bidirectional recharging to reducing user and system costs and increasing the renewable electricity share in the electricity system. That assessment shall be made publicly available. On the basis of the results of the assessment, Member States shall, if necessary, take appropriate measures to adjust the availability and geographical distribution of bidirectional recharging points in private areas and include them in the national progress reports.

In this respect, CERA in collaboration with the Ministry of Transport, Communications and Works, the Cyprus' Market Operator as well as the Cyprus' System Operators (Transmission System Operator of Cyprus-TSOC and the Distribution System Operator-DSO) has developed and implemented a Methodology for assessing the impact of current and future Electric Vehicle Charging Points (EVCPs) in the power network of Cyprus in terms of electrical flexibility and penetration of Renewable Energy Sources (RES).

3. METHODOLOGY

The methodology principles and steps, as well as the assumptions followed for assessing the impact of Electric Vehicles (EVs), and subsequently EVCPs, in the power network of Cyprus are presented in this Section.

3.1. National State of Play and Methodology Principles

To better understand the developed Methodology, the current national state of play in the electricity market landscape as well as the EVCP-related principles exploited are described in the following sub-sections.

3.1.1. Competitive Electricity Market of Cyprus

The energy sector in Cyprus is undergoing fundamental transformations concerning its structure and organisation, its institutional framework and the diversification of its energy mix. In an effort to open up the market to new participants, CERA has proposed the net-pool model as being the most appropriate trading arrangement approach for the Cyprus electricity market. The formulation of a net-pool incorporates both, a bilateral contracts market and a central Day Ahead Market. In the near future, an Intra-Day Market will be organized. The proposed design includes also a real time balancing mechanism that provides the TSO with the ability to purchase the required operational reserves, activate balancing services and settle imbalances.

Due to the delays in the implementation of the competitive electricity market in Cyprus, which mainly concern the installation of two software programs, prerequisites for the operation and monitoring of the electricity market, CERA decided on a transitory regulation of the electricity market in Cyprus, prior the full implementation of the new electricity market model. The transitory regulation is based on bilateral contracts between producers and suppliers for the supply of a standard quantity of electricity (kWh) on a monthly basis (above a threshold set by CERA – (i) for producers with a production license above 4.5 MW and (ii) for suppliers with contract for supply of energy to consumers with total agreed power above 10 MW) where settlement clearing is done on a monthly basis. The contracts involve only the provision of energy, and a simple arrangement would require no extra software for its implementation by the TSO and DSO. CERA, with a new Decision, to enable larger number of producers to participate in the transitional arrangement, decided to reduce the threshold for producers to 1 MW. This threshold has been further reduced (April 2019) to 50 kW to allow for the participation of more producers in the transitional market. The transitory regulation of the electricity market in Cyprus started on 1 September 2017 and will be in force until the full implementation of the new electricity market model.

3.1.2. Electrical Flexibly Provision and RES Integration

Flexibility provision and Demand Response (DR) are critical components in the modern energy landscape, especially with the increasing integration of RES. This section explores the mechanisms of flexibility provision and demand response, and their impacts on the integration of RES into the energy grid.

Flexibility provision refers to the ability of the power system to adjust its output or consumption in response to external signals, such as market prices or grid stability needs. Key elements of flexibility provision include:

- Generation Flexibility: The ability of power plants to ramp up or down their output quickly.
- Demand Flexibility: The ability of consumers to adjust their power usage in response to signals.
- Storage Solutions: Utilizing energy storage systems like batteries to balance supply and demand.
- Grid Infrastructure: Enhancements in grid technology that allow for better distribution and management of power flows.

Demand Response

DR is a crucial strategy in modern energy management that enables consumers to adjust their electricity usage patterns in response to market signals or grid needs and can be broadly categorized into two types based on the nature and timing of the response: Price- and Incentive-based DR.

In the context of the first category, consumers alter their electricity usage in response to price signals. This scheme includes strategies such as:

- Time-of-Use Pricing: Different rates for electricity during different times of the day to encourage usage during off-peak periods.
- Real-Time Pricing: Prices vary based on real-time supply and demand conditions.
- Critical Peak Pricing: Higher prices during critical peak periods to discourage high usage.

On the contrary, incentive-Based DR focuses on providing financial incentives to consumers for reducing or shifting their electricity use and includes strategies such as:

- Direct Load Control: Utilities remotely control high-consumption appliances like air conditioners and water heaters during peak periods.
- Interruptible/Curtailable Service: Large consumers agree to reduce their load during peak times in exchange for lower rates or other incentives.
- Demand Bidding/Buyback Programs: Consumers offer to reduce their load in response to requests from the utility, often through a bidding process.

Flexibility provision and DR are essential for the successful integration of RES. By enhancing the ability to balance supply and demand, stabilize the grid, and reduce costs, these mechanisms support higher levels of RES integration, ultimately contributing to a more sustainable and resilient energy system.

In accordance with the Article 24 of the National Law on the Regulation of the Electricity Market N. 130(I)/2021 (consolidated 2023), CERA determines via its Regulatory Decision the framework by which the participation of DR through aggregation is allowed and promoted, allowing end-users to participate together with electricity producers in all electricity markets in a non-discriminatory manner.

3.1.3. Unidirectional and Bidirectional Electric Vehicle Charging

Vehicle-to-Grid (V2G) and Grid-to-Vehicle (G2V) are advanced technologies that integrate EVs with the power grid, offering potential benefits for energy management, grid stability, and renewable energy integration. This analysis provides a comprehensive overview of both technologies, their operational principles, benefits, challenges, and future prospects.

Vehicle-to-Grid (V2G) Technology

Vehicle-to-Grid (V2G) technology enables bidirectional energy flow between EVs and the power grid, where EVs can discharge stored electricity back to the grid during peak demand periods or when renewable energy generation is low. This process requires specialized hardware (bidirectional chargers) and software to manage the energy flow and ensure grid stability.

V2G can provide ancillary services such as frequency regulation and voltage support, while it can also support balance supply and demand, reducing the need for peaking power plants. In terms of renewable energy integration, it enhances the utilization of intermittent renewable energy sources (e.g., solar, wind) by storing excess generation in EV batteries and discharging it when needed. EV owners can earn money by selling stored electricity back to the grid during high-demand periods resulting to reduced overall energy costs by shifting consumption to off-peak hours.

Despite the recognisable benefits of this technology, its deployment progress is slow due to the high capital costs for infrastructure upgrades and equipment of bidirectional chargers and supporting smart grid technology as well as the lack of standardized regulations and market mechanisms to support V2G.

Grid-to-Vehicle (G2V) Technology

Grid-to-Vehicle (G2V) refers to the unidirectional flow of energy from the grid to EVs for charging purposes that can utilizes smart charging technologies to optimize charging times and rates based on grid conditions and energy prices. Even though G2V technology can respond to grid signals, reducing or delaying charging during peak periods to alleviate grid congestion, thus supports load balancing and enhances grid reliability, it cannot provide stored energy to the grid in the domain of services like frequency regulation, voltage support, and DR to help balance the grid in the same manner as V2G can.

3.1.1. Electric Vehicle Charging Levels and Protocols

EV charging is categorized into three primary levels, each with distinct charging technologies and speeds:

Level 1 Charging:

- Technology: Utilizes a standard 120-volt AC household outlet.
- Speed: Slowest charging rate, typically adds 5 – 10 km of range per hour.
- Use Case: Suitable for overnight charging or low daily mileage needs.

Level 2 Charging:

- Technology: Requires a 240-volt AC outlet, like those used for large appliances, often connected to dedicated EVCPs.
- Speed: Medium charging rate, typically adds 15 – 100 km of range per hour depending on the EV and charger capacity.
- Use Case: Ideal for home, workplace, and public charging where faster charging is needed over several hours.

Level 3 Charging (DC Fast Charging):

- Technology: Uses direct current (DC) and high power levels (typically 400 – 800 volts).
- Speed: Fastest charging rate, can add 100 – 300+ km of range in 20-30 minutes.
- Use Case: Best for long-distance travel and quick top-ups at public charging stations along highways.

Advanced Technologies:

- Ultra-Fast Charging: High-power DC chargers exceeding 350 kW, significantly reducing charging times.

EV charging also involves several communication protocols that ensure efficient, secure, and user-friendly interactions between the EV, Charging Station, and power grid. Here's an overview of these protocols:

Level 1 and Level 2 Charging:

- IEC 62196 (Type 2): Standard in Europe, supports both AC and DC charging, with communication capabilities for safety and efficiency.

Level 3 Charging (DC Fast Charging):

- CHAdeMO: A fast charging protocol developed in Japan, used by several manufacturers worldwide. It allows for DC charging with communication between the EV and charger to manage charging parameters.
- Combined Charging System: Combines AC and DC charging using the same connector, widely adopted in Europe and North America. It incorporates Power Line Communication for high-level data exchange between the EV and the charger.

Advanced Communication Protocols:

- OCPP (Open Charge Point Protocol): An open-source protocol that enables communication between EV charging stations and central management systems. It supports various features such as remote monitoring, management, and interoperability between different manufacturers' equipment.
- ISO 15118: A protocol for V2G communication that allows bi-directional charging and energy exchange. It supports features like Plug & Charge, where the EV automatically identifies and authenticates with the charging station, simplifying the user experience.
- OSCP (Open Smart Charging Protocol): an open communication protocol between the charge point management system and the energy management system of the site owner or the system of the DSO (Distribution System Operator). This protocol communicates a 24-hour forecast of the available capacity of the power grid. The Service Provider adjusts the electric vehicle charging profiles within the limits of available capacity. OSCP is hosted by the Open Charge Alliance.
- Open Automated Demand Response (OpenADR) defines the interface to the functions and features of a Demand Response Automation Server that is used to facilitate the automation of customer response to various DR programs and dynamic pricing through a communicating client. This protocol, also addresses how third parties such as utilities, ISOs, energy and facility managers, aggregators, and hardware and software manufacturers will interface to and utilize the functions of the Demand Response Automation Servers in order to automate various aspects of DR programs and dynamic pricing.

These protocols ensure that EVs can charge safely, efficiently, and universally across different charging networks and regions. They also enable advanced functionalities like smart charging and energy management, contributing to the overall reliability and sustainability of the EV ecosystem.

3.1.2. Public and Private Electric Vehicle Charging Stations

EVCPs can be categorized into public and private stations, each serving different needs and having distinct characteristics.

According to Article 2 "Definitions" of the Regulation (EU) 2023/1804 "on the deployment of alternative fuels infrastructure", 'publicly accessible alternative fuels infrastructure' means an alternative fuels infrastructure which is located at a site or premises that are open to the general public, irrespective of whether the alternative fuels infrastructure is located on public or private property, whether limitations or conditions apply in terms of access to the site or premise and irrespective of the applicable use conditions of the alternative fuels infrastructure. Public EVCPs are typically installed in publicly accessible areas such as parking lots, shopping centers, highways, and urban centers and are available to all EV owners, often 24/7. Public EVCPs are typically owned and operated by businesses, municipalities, utilities, or third-party providers and include a variety of Charging Levels: Level 2 (AC) and DC fast chargers (Level 3).

On the contrary, Private EVCPs are located at private residences, workplaces, or private properties and provide limited access to specific users, such as homeowners, employees, or tenants. These kind of EVCPs are owned and operated by individuals, companies, or property managers, supporting charging Levels such as Level 1 (standard household outlet) or Level 2 chargers, with some workplaces or private facilities offering DC fast chargers.

Both public and private charging stations are essential for supporting the growth of the EV market, each serving complementary roles. Public stations enhance the feasibility of long-distance travel and urban charging accessibility, while private stations provide cost-effective, convenient charging solutions for daily use. Together, they contribute to a robust and comprehensive EV charging infrastructure.

3.1.3. Electric Vehicle Charging Stations and their impact on the Power Network

EVCPs, both public and private, can play a pivotal role in stabilizing power networks and facilitating the integration of RES by unlocking the untapped flexibility of the connected and available EVs. By leveraging smart charging, V2G technology, and distributed energy resources, these stations can provide essential grid services, optimize renewable energy use, and support the transition to a sustainable energy future. Optimal energy management of both public and private EVCPs can reduce the need for expensive peaking power plants and infrastructure investments, while EV owners also benefit from lower energy bills through participation in DR programs by exploiting price signals that reflect the true cost of electricity, leading to more efficient market operations and investment decision.

Flexibility provision can impact the power network operation via two pathways, either through Centralised electricity markets run by the Market Operator or through Local Flexibility Markets (LFMs) run by DSOs or via TSO/DSO Coordination. Due to the fact that Cyprus is a small non-electrically connected island with a single DSO, it is assumed that the operation of LFMs will not be assigned to another party / body other than System Operators.

In terms of Centralised electricity markets and more specifically provision of EV-generated flexibility can provide significant support for ancillary services, which are essential for maintaining grid stability and efficiency. In this scope, EVs can offer frequency regulation services by adjusting their charging rates in response to grid frequency deviations. This rapid response helps to maintain the balance between supply and demand, stabilizing the grid frequency. Furthermore, EVs can provide voltage support by injecting or absorbing reactive power through their inverters. This helps to maintain the voltage levels within acceptable limits, improving the quality of power supplied to consumers. Likewise, EVs, particularly when aggregated or through large-scale EVCPs, can act as a reserve that can be called upon quickly in the event of a sudden loss of generation or an unexpected increase in demand. This spinning reserve capability enhances grid reliability and resilience. In the event of a major grid outage, EVs with V2G capabilities can assist in black start operations by providing the initial power needed to restart generation plants and restore the grid. By providing ancillary services locally, EVs can also help defer or avoid investments in traditional grid infrastructure upgrades. This cost-effective solution supports the grid without the need for significant capital expenditure.

On the other hand, LFMs enable DSOs to balance electricity supply and demand at the local level. This is crucial as more distributed energy resources (DERs) like solar panels, wind turbines, and battery storage are integrated into the grid. Through these markets, flexibility extracted by EVCPs can help manage and reduce grid congestion, minimizing the need for expensive grid infrastructure upgrades. By using local resources to address congestion, DSOs can defer or avoid costly investments in new lines or substations. By leveraging on local flexibility of EVCPs, DSOs can also enhance grid stability and reliability by quickly responding to fluctuations in supply and demand, preventing potential disruptions and ensuring a stable electricity supply. Moreover, LFMs can allow DSOs to better manage the variability and intermittency of renewables by tapping into local flexible resources that can adjust their output or consumption in response to grid conditions. In addition, these markets promote innovation and the development of new business models. They create opportunities for new market participants, such as aggregators and prosumers, to offer their flexibility services, fostering a more dynamic and competitive energy market.

In accordance with the Article 50 of the National Law on the Regulation of the Electricity Market N.130(I)/2021 (consolidated 2023), CERA by its Regulatory Decision determines the framework that allows and provides incentives to the DSO to procure flexibility services, including congestion management, with the aim of improving efficiency in terms of the operation and development of the distribution system. According to the Article 51 of the same Law, in compliance with the provisions of the National Law on the Promotion and Development of Infrastructure of Alternative Fuels, CERA with its Regulatory Decision determines the regulatory framework, in order to facilitate the connection of publicly accessible or private recharging points with the distribution network and with the said regulatory framework ensures that the DSO cooperates in a way that does not introduce discrimination with any company that owns, develops, operates or manages recharging points for electric vehicles, regarding, inter alia, connection to the grid.

3.2. Methodology Description

In order to develop a unified methodology which will be able to set the foundations that will meet the requirements of both Article 15(3) and 15(4), a comparative breakdown analysis of the objectives was undertaken as follows:

Table 1. Comparative breakdown analysis of Article 15(3) and 15(4).

Article 15(3)	Article 15(4)
Reference (Baseline) Scenario (current state). Examines: A) Current Flexibility of the power system B) All types of EVCPs: • smart and bi-directional recharging • all power outputs, • public as well as private	Future Scenario (future state). Examines: A) Future Flexibility of the power system B) All types of EVCPs: • smart and bi-directional recharging • all power outputs, • public as well as private
Recommendations regarding • the type of recharging point, • the support technology and • the geographical distribution	
Appropriate measures to install additional EVCPs	Appropriate measures to adjust the availability and geographical distribution of bidirectional recharging points in private areas
Contribution to RES Penetration Levels	Contribution to RES Penetration Levels
	How EVCPs contribute to reducing costs for the user and the system

Based on the preformed comparative breakdown analysis, the Methodology is divided into two different Scenarios:

- Reference (Baseline) Scenario for Year 2023
- Future Scenario for the Year 2028

Both aforementioned Scenarios are then categorized into two sub-scenarios: i) Uncoordinated Charging and ii) Coordinated Charging. The first one concerns a combination of real EV Charging Profiles collected via various EVCPs as well as the provided ENTSO-e EV Charging Profiles that were also utilised in the National Energy Climate Plan (NECP). The latter sub-scenario regards coordinated EV Charging Profile that follows a “smart” charging approach that can be beneficial for the overall Demand Profile of Cyprus towards a lower system costs and higher RES penetration levels.

The following figure presents a high-level flowchart of the followed methodology.

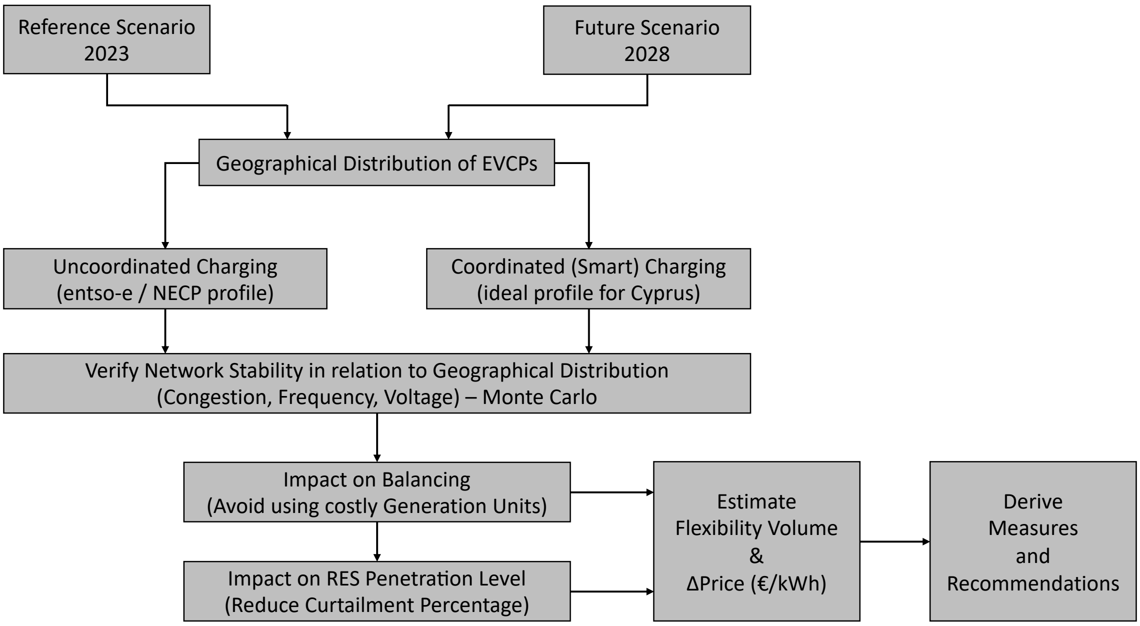

Figure 1. High-Level Methodology for assessing the impact of EVCPs in the power network of Cyprus.

As depicted in Figure 1, the impact of EVCPs is evaluated based on the network stability (congestion, frequency and voltage levels) of the investigated network topology and can be classified as the impact on balancing and the impact on RES penetration levels. The first one concerns the avoidance of deploying costly generation units for meeting the total load demand of the system, while the latter is related to the Hosting Capacity which is defined as the amount of RES that can be connected to a specific Busbar (location) without violating any operational limit.

The operational limits were defined according to the current Cyprus Grid Code and the Technical Manual for connection of RES and there are as follow:

- Maximum Busbar Voltage Variation before and after connection = 2%
- Maximum Voltage Deviation +10%
- Minimum Voltage Deviation -10%
- Maximum Branch Element Loading = 100%

Both aforementioned indices of impact are strongly related to the flexibility provision capabilities of EVCPs.

As conditions for the Future Scenario of the year 2028 cannot be easily defined, a Monte-Carlo approach is implemented to assess the impact of the future rollout of public and private EVCP in the Cyprus' distribution network. The simulations are undertaken using historical data for the case of Reference Scenario and estimated forecasts, that consider projections for load growth, EVCP and PV levels, for the Future Scenario of 2030. The security assessment is performed with automated simulations using Python, an open-source Programming Language, with DIgSILENT PowerFactory, which is power system analysis software application for use in analysing generation, transmission, distribution and industrial systems. DIgSILENT PowerFactory is utilised to capture the geographical distribution of EVCPs and RES by replicating the power network of Cyprus. The developed Python script has been utilized as the computational engine, to evaluate the hosting capacity of Medium Voltage (MV) as well as Low Voltage (LV) distribution networks under the identified scenarios. For each scenario, 1000 quasi-dynamic (time sweep load flows) simulations are performed using historical data selected randomly. For each simulation, 6 hours in each day are analysed (4p.m, 8p.m, 12a.m, 4a.m, 8a.m, 12p.m). For each iteration, the number of new EVCPs and PV systems is selected using a uniform distribution from 3 to 10 and the locations where the new PV systems are connected are uniformly selected among all possible busbars. Finally, the installed capacity of the new PV systems as well as public and private EVCPs is randomly selected using a uniform distribution. At the end of each scenario analysis, the aggregated results from the 6000 hours are used to check the number of violations and other technical parameters of the system. The following attributes are assessed in each analysis:

- Power Transformer Loadings
- MV Feeders Maximum Loading
- Maximum MV Feeder voltage
- Minimum MV Feeder voltage
- Maximum voltage difference before and after a new RES connection
- Tie line loading

To avoid any potential violation of grid constraints, a new RES connection request is considered feasible only if the maximum voltage difference (after the potential connection of RES) at the Point of Common coupling (PCC) is below 2%. In general, this criterion is usually the limiting factor of the Hosting Capacity in the MV distribution system of Cyprus.

The steps followed for the stochastic Monte-Carlo approach, performed for the Future Scenario, are illustrated in the figure below.

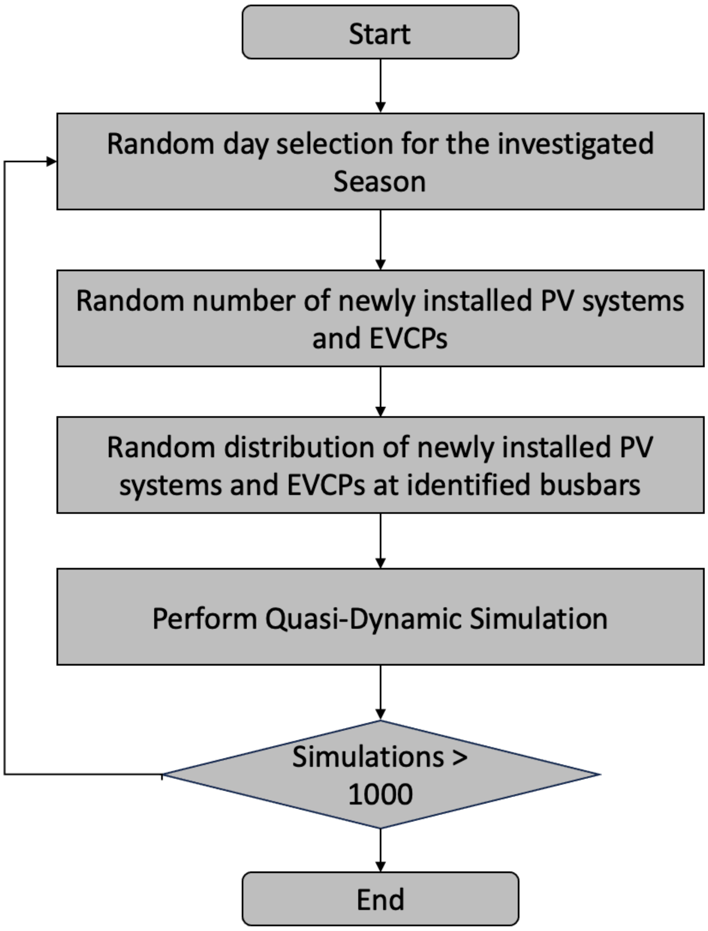

Figure 2. High-Level Methodology for the stochastic distribution of PV Systems and EVCPs at the identified busbars.

In terms of flexibility provision and the impact on the system balance as well as the local grid constraints, this task was undertaken in two perspectives: i) the impact on the Cyprus' power system form the TSOC and Market Operator (MO) perspective and ii) local impact on the distribution network from the DSO perspective.

The impact of high EVCP penetration levels in the cost of the Cyprus' power system, from the TSOC and MO perspective, is examined via the commonly used

Unit Commitment and Economic Dispatch approach. The tool which was used in the study is the Unit Commitment and Economic Demand tool, developed by KIOS Research and Innovation Centre of Excellence for the TSO Cyprus. The input to the tool is the 30-minute timeseries of Demand and RES, along with the requested timeseries of reserves. Additional input is the availability of the generators and the operation cost of each generator; these values were the same in all scenarios. Moreover, a penalty cost for RES curtailment is applied.

The output of the tool, among other is:

- Dispatch for each conventional unit (Timeseries - MW)
- Curtailed energy per technology (Timeseries - MW)
- RES dispatch for wind and PV (Timeseries - MW)
- CO_2 emissions (daily – tones)
- Cost of generation – multiple data (daily - €)

The analysis was performed for each month, for the different Scenarios of the study. The results of the study should be considered optimistic in terms of RES penetration and costs, since all generators were considered available in the study, without any significant grid restrictions. Under this aspect, the results should be used for comparison of the different scenarios, and not as absolute values of individual analysis.

From the DSO perspective, and in the context of LFMs, the provision of flexibility extracted by the available EVs of each EVCP, is expected to be used mainly for congestion avoidance. It should be noted that reducing or eliminating congestions will have also a beneficial effect on voltage stability.

Finally, based on the resulting findings, relevant suggestions for measures and policy recommendations are derived.

3.3. Case Study Description

The case study power network which shall be utilised for assessing the impact of EVCPs in the network of Cyprus in described in this Section.

Selecting a case study power network that is representative of all characteristics is crucial for ensuring that the insights and solutions derived from the study are broadly applicable. Such a network typically encompasses a diverse range of factors including varied demand patterns, different generation sources (e.g., renewable and non-renewable), various grid topologies and scaled as well as different geographical and climatic conditions. This diversity ensures that the case study reflects the complexities and challenges of real-world power networks, allowing for comprehensive analysis and generalizable conclusions that can inform policy-making, planning, and optimization strategies across different regions and contexts. In this domain, the Transmission Substations of Dhasoupolis and Athalassa, and the Primary Substations of New General Hospital and the University Primary have been selected for the analysis. Those Substations (S/S) represent almost all different types of substations, load demand, renewable generation and weather characteristics along with the EVCPs specificities and considerations for both Scenarios.

The utilisation of Distribution Network shall also support in assessing the untapped flexibility potential of EVCPs in the context of LFMs.

Any results yielded via the Case Study Network shall be extrapolated to the whole power system based on a series of clusters grouped on the basis of the identified network characteristic.

The following figures depict the network topology of the identified Transmission and Primary Substations, where colour variations represent different feeders.

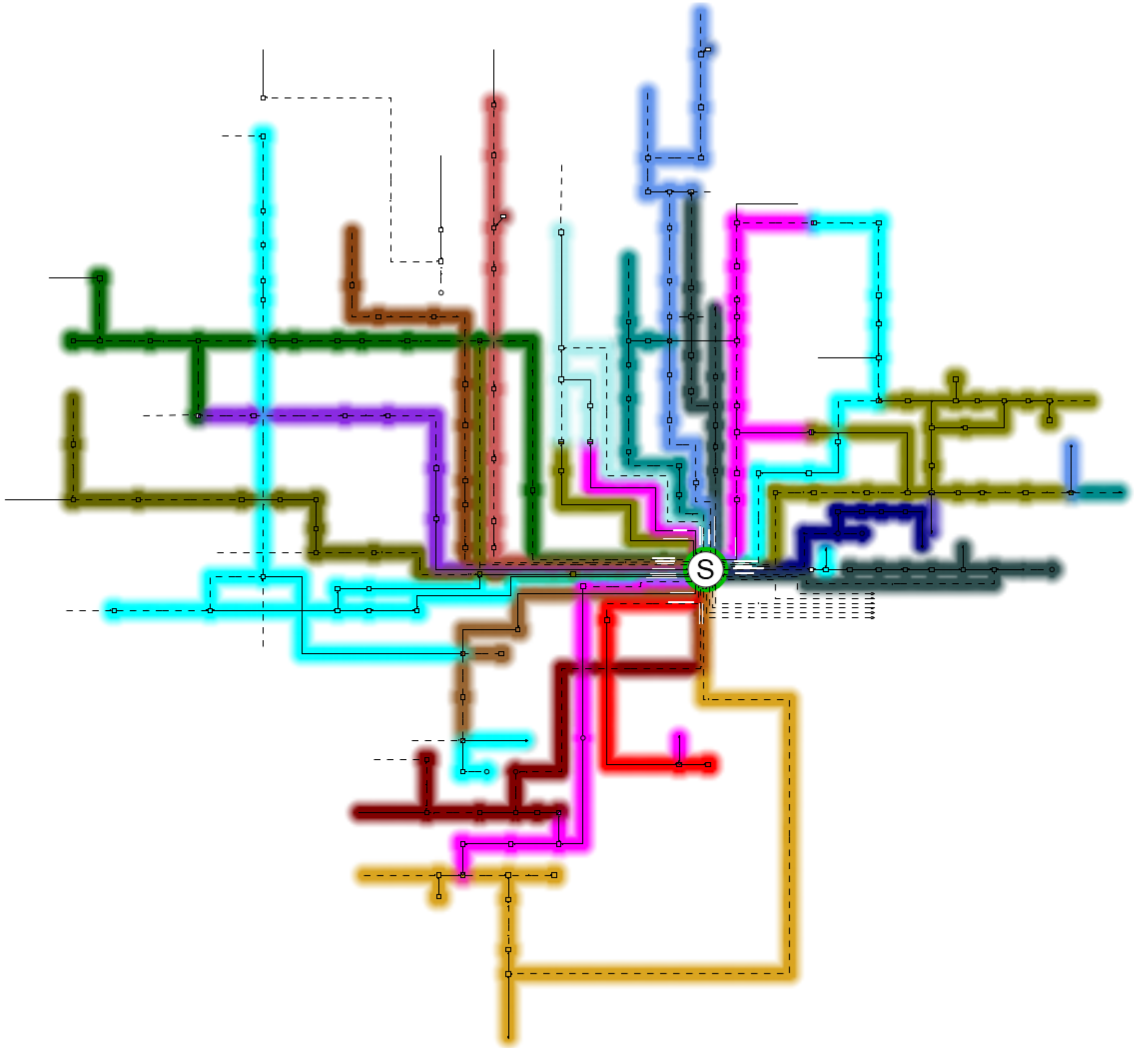

Figure 3. Network Topology of the “Dhasoupoli” Transmission S/S.

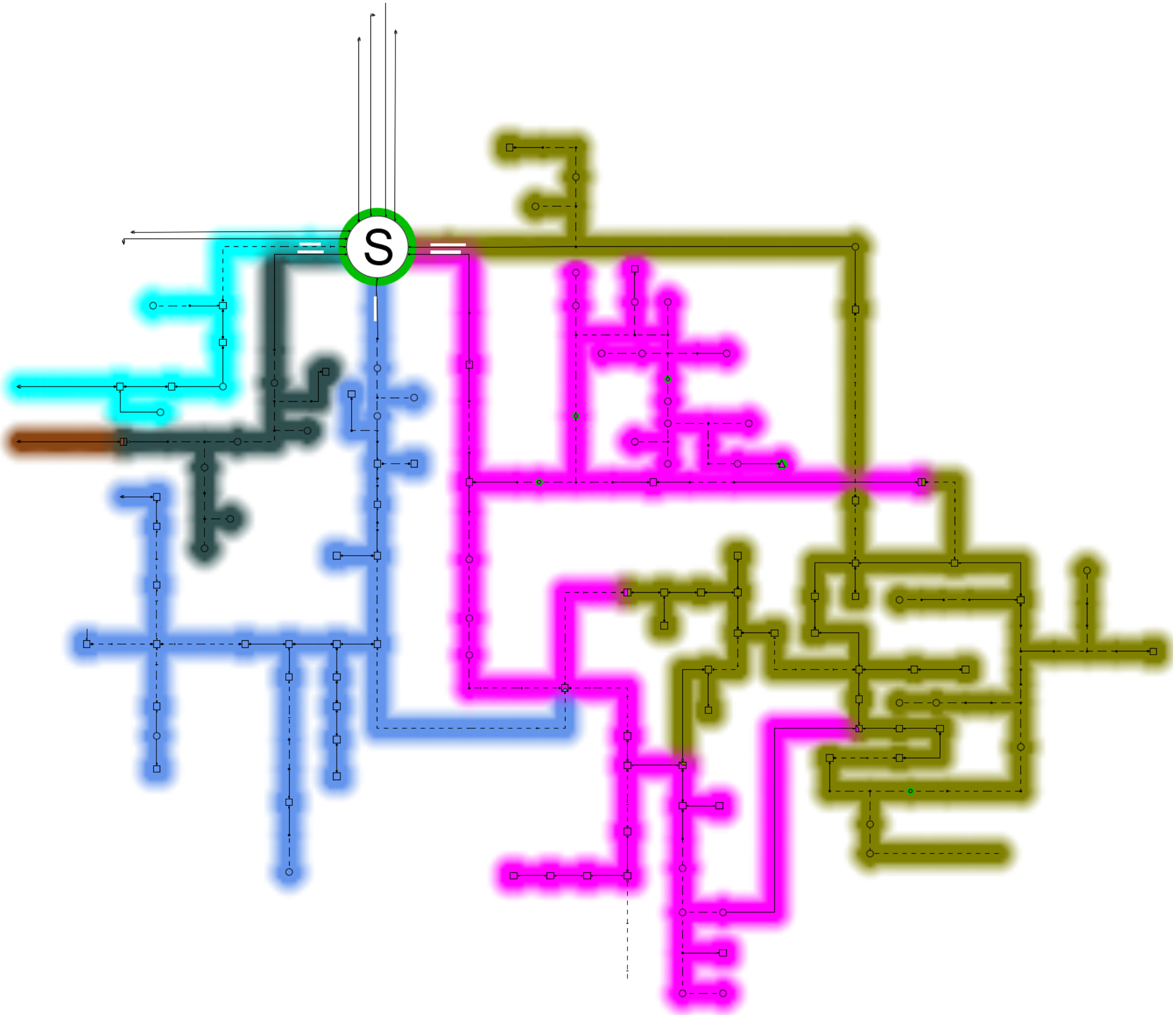

Figure 4. Network Topology of the “Athalassa” Transmission S/S.

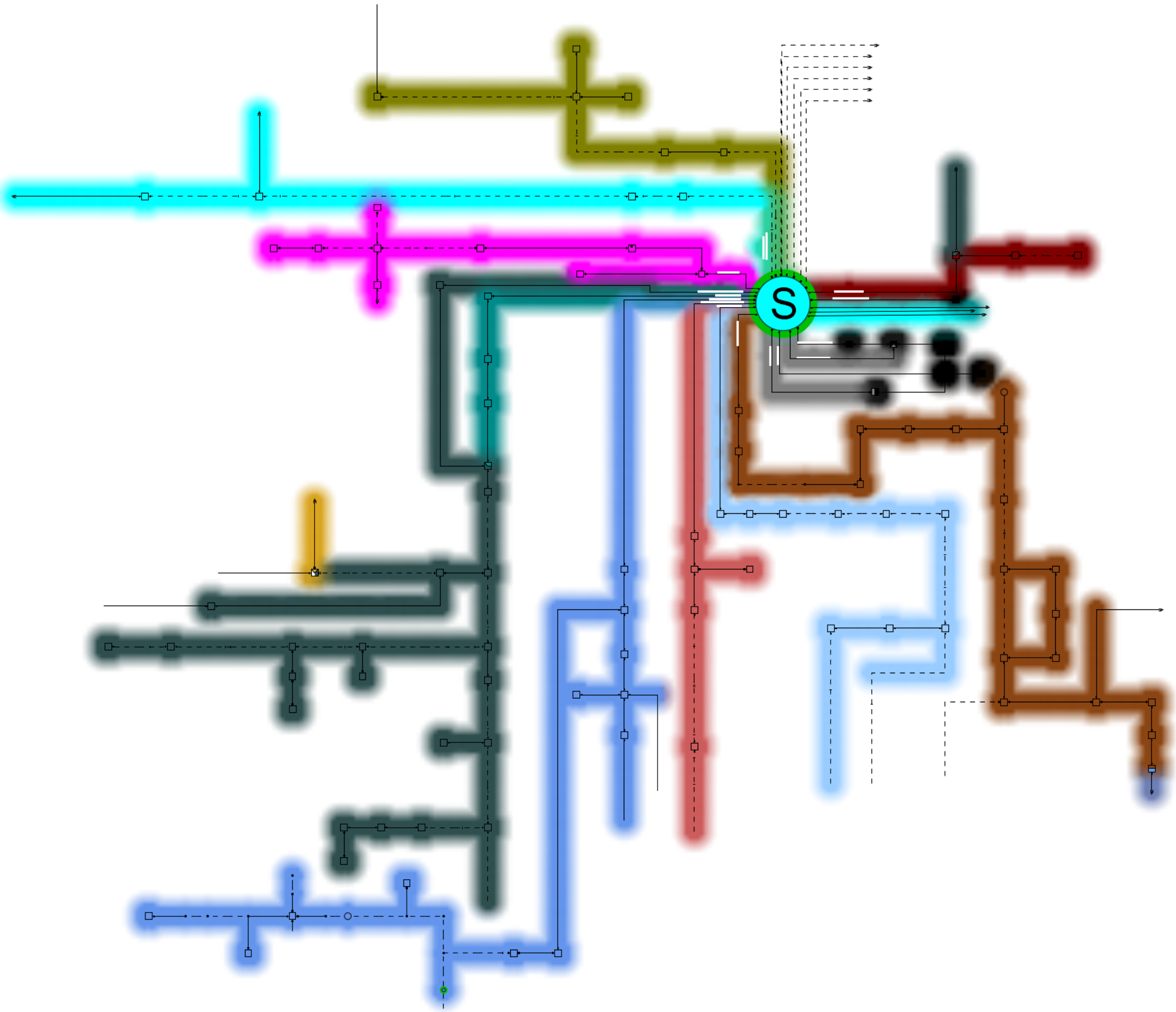

Figure 5. Network Topology of the "New General Hospital" Primary S/S.

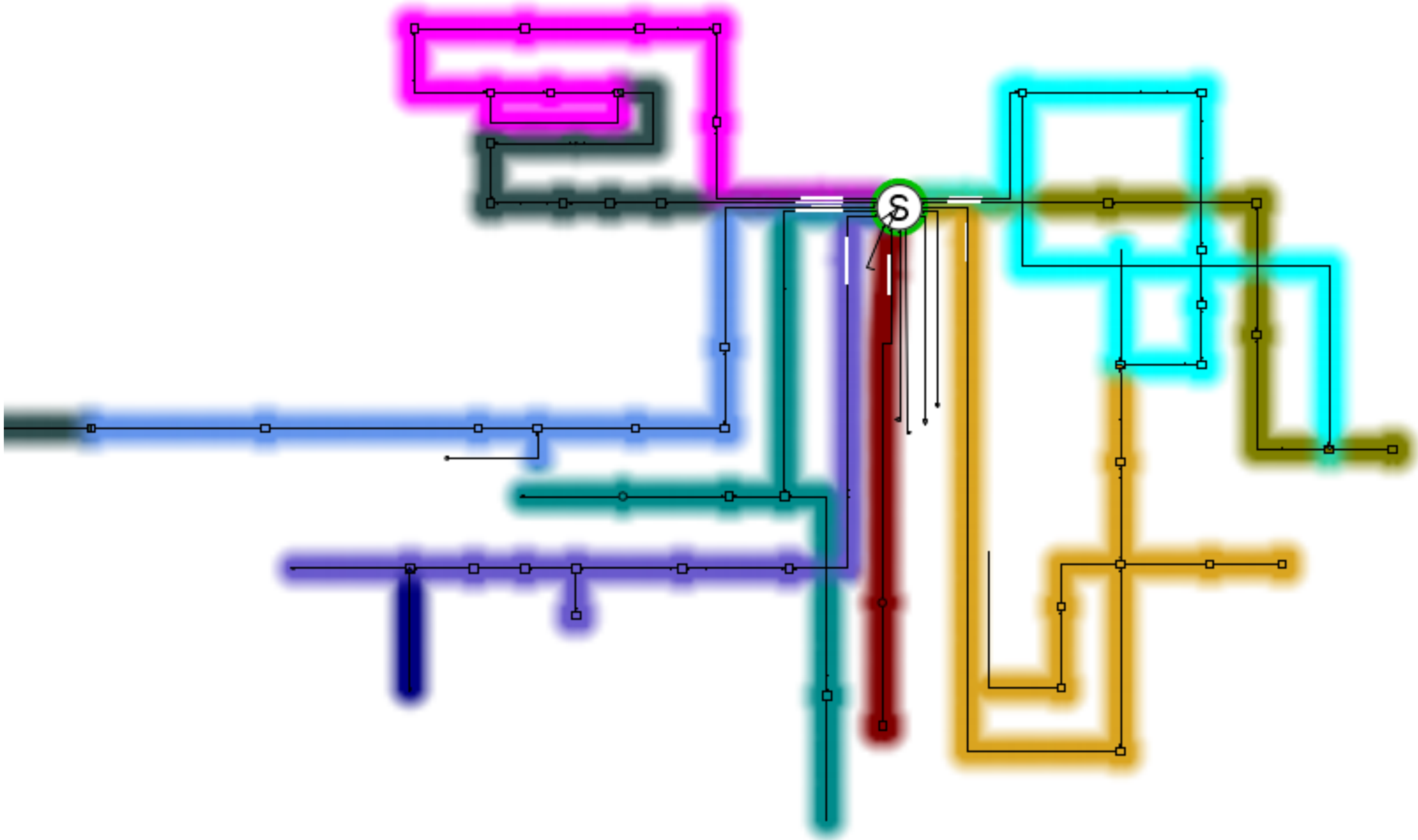

Figure 6. Network Topology of the “University of Cyprus” Primary S/S.

The characteristics of the selected Case Study Distribution Network, in terms of RES and EVCP penetration levels, are tabulated in the following Tables.

Table 2. Characteristics of the Case Study Distribution Network.

Substation	Nominal Capacity (MVA)	Load Characteristics	RES Penetration	RES Installed Capacity
Dhasoupolis S/S	120	Residential and Commercial	Low	14
Athalassa S/S	63	Residential	High	38.5
New General Hospital Primary S/S	N/A	Commercial	Medium	5
University of Cyprus Primary S/S	N/A	Commercial	High	8

Table 3. Public EVCP levels of the Case Study Distribution Network.

Substation	Number of EVCPs	Total Installed Capacity (kWp)
Dhasoupolis S/S	4	88
Athalassa S/S	0	0
New General Hospital Primary S/S	6	432
University of Cyprus Primary S/S	5	110

Table 4. Private EVCP levels of the Case Study Distribution Network.

Substation	Number of EVCPs	Total Installed Capacity (kWp)
Dhasoupolis S/S	12	123
Athalassa S/S	6	70
New General Hospital Primary S/S	9	105
University of Cyprus Primary S/S	0	0

In order to evaluate how EVCPs contribute to reducing costs for the whole power system, a higher-level power network analysis, including Unit Commitment and Economic Dispatch strategies, is deployed. This analysis concerns the identification of the total monthly demand curves as well as the conventional generation curves for each one of the generation units. The connection of those profiles shall aid in pinpointing the flexibility requirements of the Cyprus' power system as well as their associated reduction of its cost.

The basis for the electricity demand profile rendering was the historical timeseries of for 2023 at 30 min resolution:

- Total Electricity Generation (Demand)
- Distributed generation of PVs, biomass and small conventional units
- Wind generation
- Timeseries of the Estimated curtailment for wind and PV generation
- Installed capacities of RES
- Total Demand of public and private EVCPs

The theoretical values of the generation of RES are not measured, since only the generated power after curtailment is measured, the timeseries of PVs and wind were reconstructed taking into consideration the measurements and curtailment estimations. Then, for PVs and wind, based on the installed capacity, the unitary timeseries was constructed for 2023.

Based on the data, monthly typical curves for 2023 were developed for Demand, and RES generation for each technology. Demand profiles for 2023 are shown in the following Figure. Since the demand profiles correspond to actual measurements, they include the charging demand for 2023.

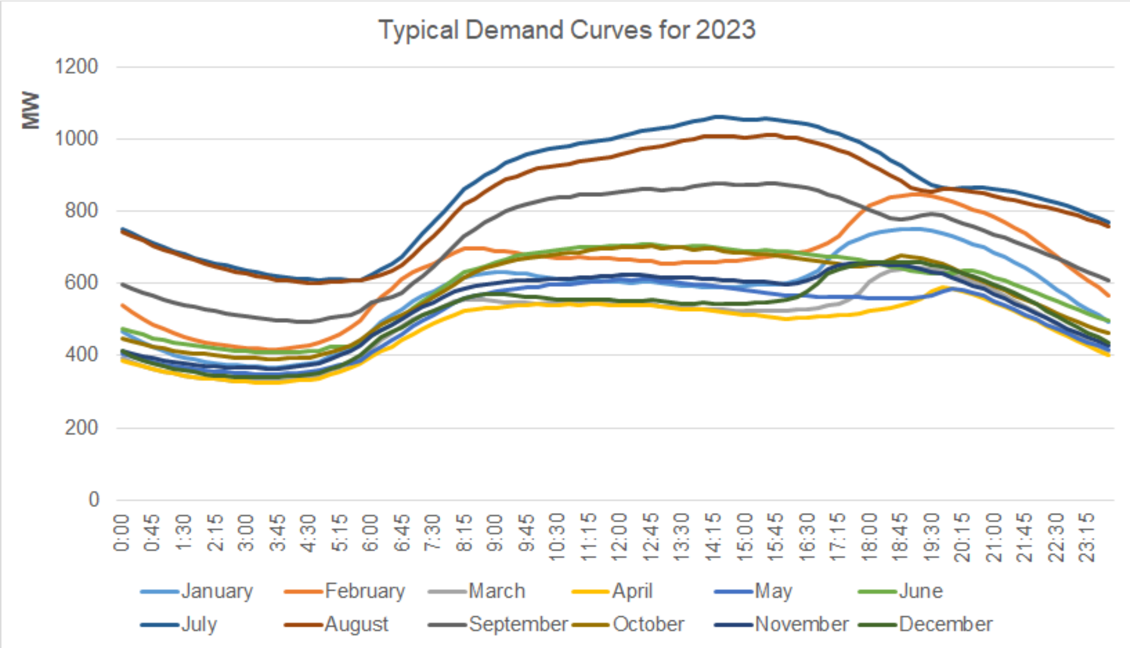

Figure 7. Typical monthly Demand Curves of the Cyprus' power network for the Reference Year.

Due to the sensitivity of the information, conventional generation unit profiles used in the context of this study are presented in an aggregated form as depicted in the Figure below. Where conventional profiles during sunshine hours are indication that RES curtailment is performed during that period.

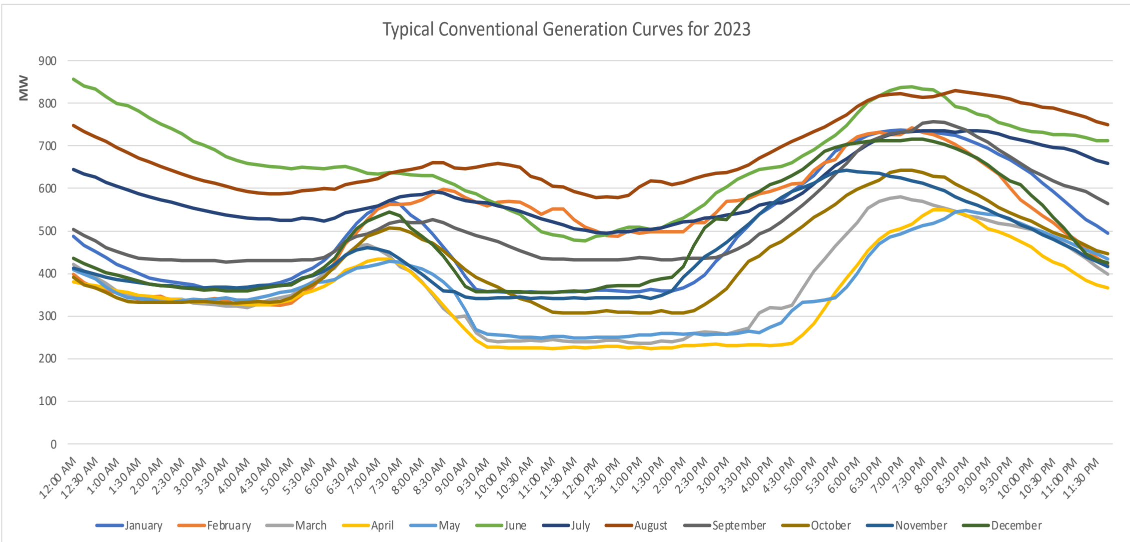

Figure 8. Typical monthly Conventional Generation Curves of the Cyprus' power network for the Reference Year.

3.4. Methodology Assumptions

In terms of the Reference Scenario, no assumptions were considered as this is based on real data and information as provided by the System Operators. For this Scenario a unidirectional charging flow is considered. This is justified not only by the absence of suitable equipment but also due to the lack of incentive mechanism that can promote bidirectional charging. On the contrary, various assumptions were made for the Future Scenario of Year 2028.

In order to delve into the seasonality effect, three periods are identified:

- Winter Season (SC1) that represents high winter demand, where there is negligible RES contribution during peak load at evening hours and relatively medium RES generation.

- Middle Season (SC2) that represents low demand period, where RES generation is very high, resulting to expected RES curtailments.

- Summer Season (SC3) that represents high summer demand, where RES contribution is very high during midday peak hours.

To investigate the impact of different EV charging strategies, five Charging Scenarios are formulated. The first (CS1) is based on the actual measurements of the Reference Scenario of year 2023. All the identified Seasons and investigated Scenarios are benchmarked compared to the baseline charging strategies followed for the Reference Scenario of Year 2023. This is deemed as the Business as Usual (BAU) practice and considers unidirectional charging (G2V) in a sense of uncoordinated strategy and a low penetration level of EVs and EVCPs.

The second (CS2) is the estimation of the actual Demand for 2023 without the charging energy. This was computed as the difference of the timeseries of charging from Demand for each typical curve. This scenario is used to compare charging effect for existing system.

The third scenario (CS3) represents the projection for 2028 with the expected uncontrolled charging energy. This scenario acts the basis for comparison of the other two scenarios for the expected gain from controlled EV charging.

The fourth scenario (CS4) considers a controlled EV charging curve, which aimed to smooth the Total Demand curve, in order to decrease the expected peaks and increase the expected valleys of the conventional curve. The conventional curve is the demand from conventional power plants, which results as the difference of Final Demand and RES generation. This scenario considers that all EVCPs have the technological capability to provide flexibility through V2G technology. This is considered as the best Charging Scenario.

The fifth scenario (CS5) considers a similar, more realistic scenario to the fourth one, under the condition that there are limitations to the technological advancements and knowledge towards untapping the flexibility potential at its full scale.

The following Figures present the Season Scenarios compared to selected Charging Scenarios and Total Demand for the Future Year of 2028.

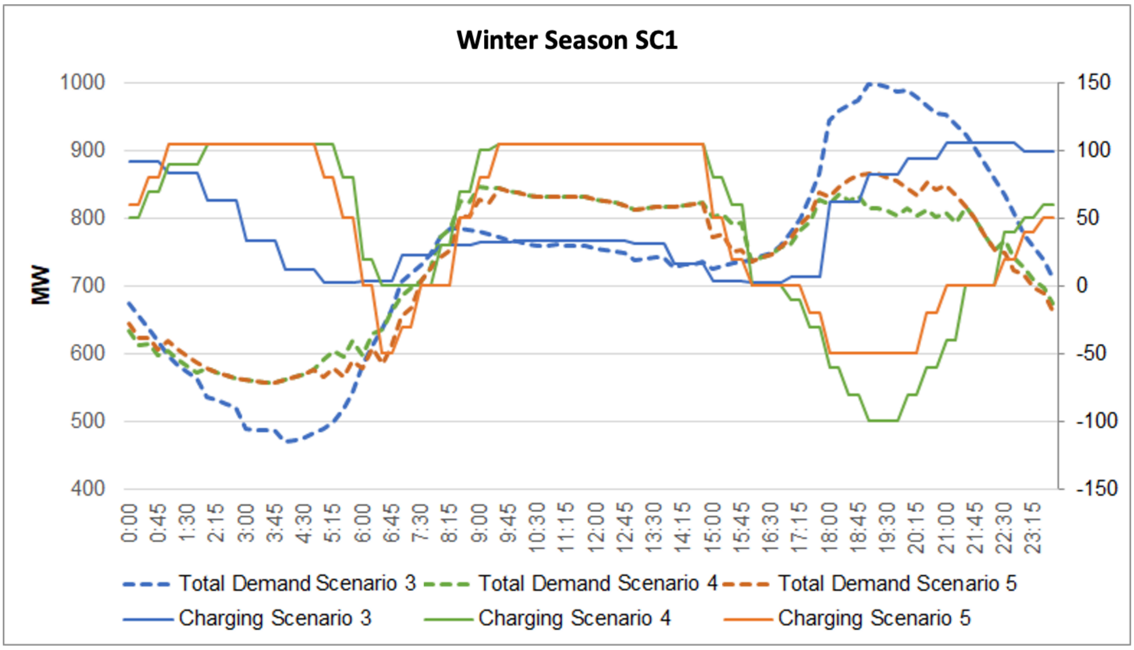

Figure 9. Total Demand in MW (left axis) and Charging profile in MW (right axis) for typical day of Winter Season of Future Year 2028.

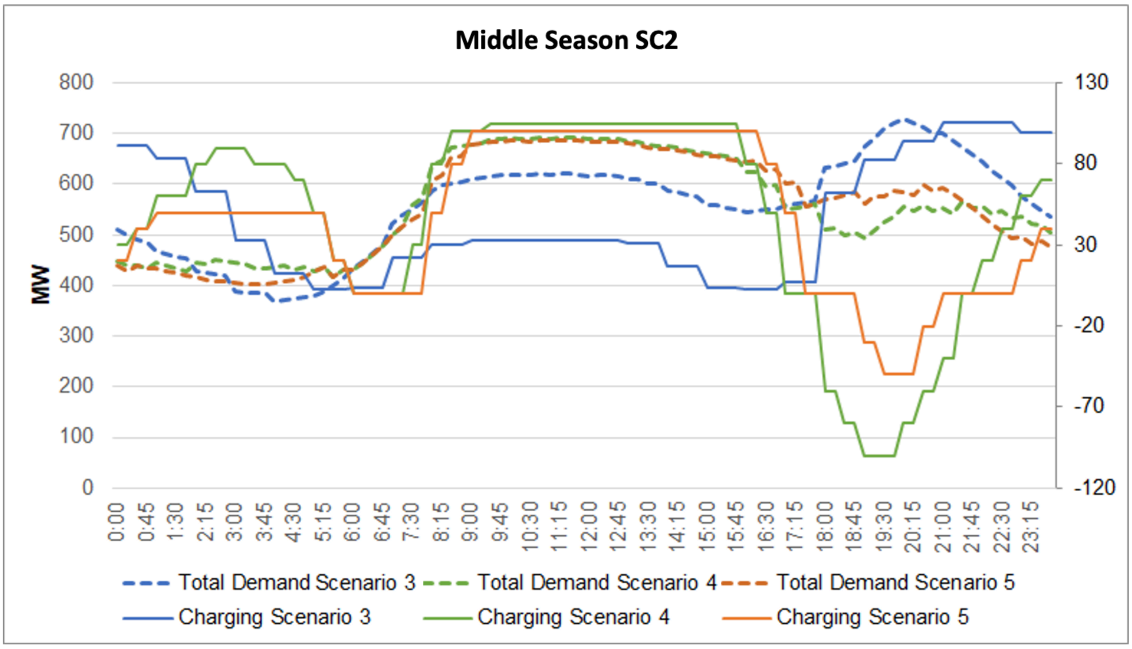

Figure 10. Total Demand in MW (left axis) and Charging profile in MW (right axis) for typical day of Middle Season of Future Year 2028.

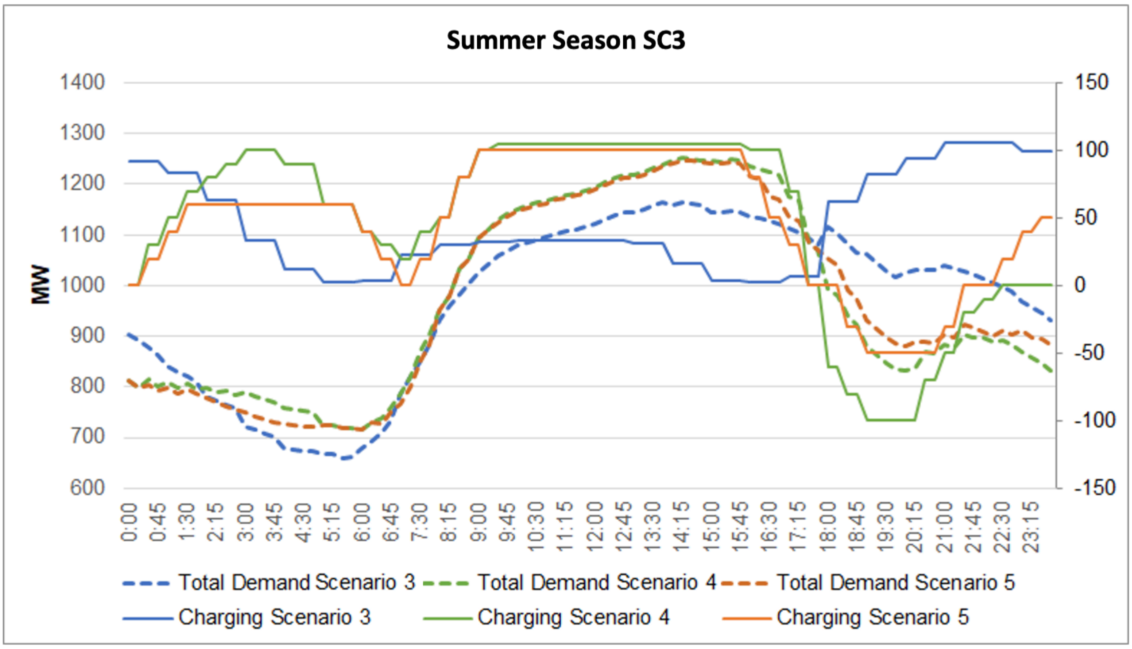

Figure 11. Total Demand in MW (left axis) and Charging profile in MW (right axis) for typical day of Summer Season of Future Year 2028.

Following the distribution strategy presented in Section 3.2, the allocation of both RES and EVCPs for the Future Scenario of Year 2028 is assumed to take place as follows:

- Number of EV per Substation = normal distribution with mean of 75 and standard deviation of 50
- Installed capacity of each EVCP = uniform distribution from 22 kWp to 150 kWp
- Number of new PV systems per substation = uniform distribution 1 to 3
- Installed Capacity of each new PV system – uniform distribution from 200 kWp to 3000 kWp.

In order to compromise the unavailability of proper market price signals due to fact that neither the Competitive Electricity Market nor LFMs are operational in Cyprus, several assumptions have been also made in terms of flexibility provision and cost reductions for the Future Scenario of Year 2028.

In terms of flexibility services offered to the TSOC, it can be safely assumed that those are related to the avoidance of committing costly generation units and the participation in the ancillary services market.

However, the case of local flexibility provision is more difficult to evaluate due to lack of data. As the LFM facilitator, the DSO takes the role of the price-maker who compensates the EVCP Operators / DR Aggregators at a contracted price for alleviating distribution grid violations at his area of responsibility (Regulatory Decision on the formulation of the corresponding framework is on-going). In the scope of this study, the cost of flexibility procurement and activation is assumed to be equal to expected distribution network investments (network expansion) for congestion avoidance. To this end, the expected Total Grid Investments Costs for the period 2023 - 2034, based on the DSO's Ten-year Development Plan for the Distribution System is utilised. For the calculations of net present values of all cash flows a discount rate of 1.5% has been assumed. The grid investments are calculated only for the MV and LV Overhead Lines, MV and LV Underground Cables and for distribution S/Ss. However, only a portion of this cost reflects investments of congestion avoidance. To identify the cost percentage corresponding to congestion avoidance the Congestion Factor for each equipment type is defined. Congestion Factor (CF) is the percentage of the equipment that is expected to be replaced/reinforced due to congestion and these factors have been estimated by the DSO. The following Table summarises the CFs estimated per equipment type.

Table 5. Estimated Capacity Factors per equipment type.

Equipment Type	Capacity Factor (%)
MV U/H	11.00
MV O/H	30.00
LV U/G	9.00
LV O/H	27.00
PM Transformers	18.00
GM Transformers	9.00

Another assumption made in the scope of this study is related to the Peak Demand reduction due to the provision of flexibility services by the available EVs connected at both public and private EVCPs. Reduction in system Peak Demand is expected to reduce the number of congestions in the Distribution Network. In order to evaluate the number of congestion reduction the Average Peak Responsibility (APR) Factor has been introduced and can be calculated as follows:

$$APR = \frac{Equipment\ Load\ during\ Peak\ Period}{Peak\ Load\ of\ Equipment} \qquad (1)$$

As seen in Equation 1, APR is the ratio of the loading of the equipment during system peak period to the peak load of equipment. Since APR is directly related with system Peak Demand, it can be used to estimate the effect of system Peak Demand to the equipment loading. The relationship between the Peak Demand Reduction with the CF and R, is described by the Adapted Congestion Factor (ACF) for each equipment type, which can be estimated as follows:

$$ACF = (1 - Peak\ Demand\ Reduction) * CF * APR \qquad (2)$$

Since the Peak Demand Reduction will be estimated based on the simulation results of the developed methodology, the estimated ACFs are presented in the Results Section.

Congestions in MV and LV Equipment of the Cyprus' distribution network are assumed to occur mainly due to the two following reasons:

- Congestion Use Case 1 - Increased Demand (Load) combined with low levels of RES generation. This situation is expected during night hours, mainly due to EVs and in winter months where the RES generation is relatively low while electricity is heavily being utilized for heating.
- Congestion Use Case 2 - Increase Generation from RES combined with low demand. This situation is expected in middle season (autumn and spring) where the generation from RES is approximately maximum while demand is minimum.

In this domain, and in the scope of estimating the Total Flexibility Energy Units [MWh] required and subsequently the Flexibility Procurement Price [€/MWh] for which the EV owners can be compensated for their EV flexibility, the feeder-related factors assumed to be more impactful for local congestion are:

- <u>Num. Of Feeders with Overload:</u> Calculated based on the Percentage of current feeder loading and future peak demand.
- <u>Num. of Days with Overload</u>: Calculated based on Historical data, (i.e number of days of High Demand Combined with low level RES generation) and predicted load curves (TSO).
- <u>Num. Of Hours of Overload:</u> Calculated based on Predicted load curves and future pre-diction of peak demand.
- <u>Requested Power Reduction per Feeder:</u> Evaluated based on current feeder loadings and the predicted load profiles. This value is assumed to be limited to 2.5 MW which is the additional power rating of the 70 mm^2 Cu line compared to 32 mm^2 Cu.

The estimation of the aforementioned parameters shall aid in estimating the Total Flexibility Energy Units [MWh]. Nevertheless, Flexibility Procurement Price [€/MWh] is also a function of the percentage occurrence of the flexibility procurement. According to the loading conditions of each feeder, Flexibility Class can be assumed to be categorized as follows:

- Critical Flexibility: occurs when a feeder is congested more than 120% of its nominal capacity.

- Normal Flexibility: requested when the loading of the feeder is between 105% to 120% of the nominal feeder capacity.

- Non-Critical Flexibility: requested when the Feeder is expected to be loaded between 95-105%.

Based on the Substation Capacity [MW], the weighted average of each Flexibility Class has been assumed to match the values shown in the following Table for all distribution S/Ss.

Table 6. Weighted Average Occurrence Percentage per Flexibility Class.

Substation	Capacity (MW)	Non-Critical Flexibility	Normal Flexibility	Critical Flexibility
Alambra	54	37.51%	51.59%	10.90%
Dhasoupoli	120	65.37%	4.15%	3.11%
Ergates	63	51.30%	9.93%	9.56%
Lakatamia	80	22.56%	92.88%	0.00%
Renos Prentzas	120	61.22%	7.93%	2.45%
Papacostas	94.5	7.41%	3.73%	0.00%
Sotera	63	100.00%	0.00%	0.00%
Karvounas	30	98.11%	0.07%	0.00%
Latsia	80	14.20%	10.30%	0.00%
Seminary	111.5	19.77%	95.18%	1.11%
Strovolos	94.5	18.99%	26.39%	0.00%
Athalassa	63	66.96%	2.89%	2.67%
Larnaca	94.5	64.64%	3.11%	1.63%
Kokkinotrimithkia	63	35.58%	98.74%	17.35%

Finally, the Flexibility Procurement Price [€/MWh] (FPP) is a function of Weighted Average Occurrence Percentage, the Total Cost of activating flexibility for the Total Flexibility Energy Units required at LFM level. FPP is assumed to be estimated as follows:

$$Flexibility\ Procurement\ Price = \frac{Occurrence\ Percentage \times Total\ Flexibility\ Activation\ Cost}{Total\ Flexibility\ Energy\ Units} \quad (3)$$

It should be noted that the upcoming Regulatory Decisions, for the under-process formulation of DR framework as well the framework for offering DSO incentives to procure flexibility, can potentially create variations on the foundations used for the assumptions made in the scope of this study.

4. RESULTS

The results obtained by applying the developed methodology is presented in this Section. The results are described separately for each one of the investigated Scenarios.

It must be noted that the derived results for the Future Scenario are significantly driven by the assumptions presented in Section 3 and even though the findings are deemed as satisfactory indications, the imminent full operation of the Competitive Electricity Market and the upcoming facilitation of LFMs can alter the national energy landscape, and subsequently the outcome of this assessment.

4.1. Reference Scenario – Year 2023

The datasets used for the year 2023 (baseline), correspond to the active and reactive power measurements for 2023 at the starting point of each MV feeder as obtained by TSOC Supervisory Control and Data Acquisition (SCADA) system. The loads have been distributed to the distribution substations along the MV Feeders based on the installed capacity of each MV/LV transformer. In the scope of this analysis, the average active power load demand as well as the daily average RES and EVCP profiles have been utilised. The daily average profile of each one of the investigated MV feeders consisting of the Case Study power network, as derived by the exploited real datasets, are presented in the following Figures.

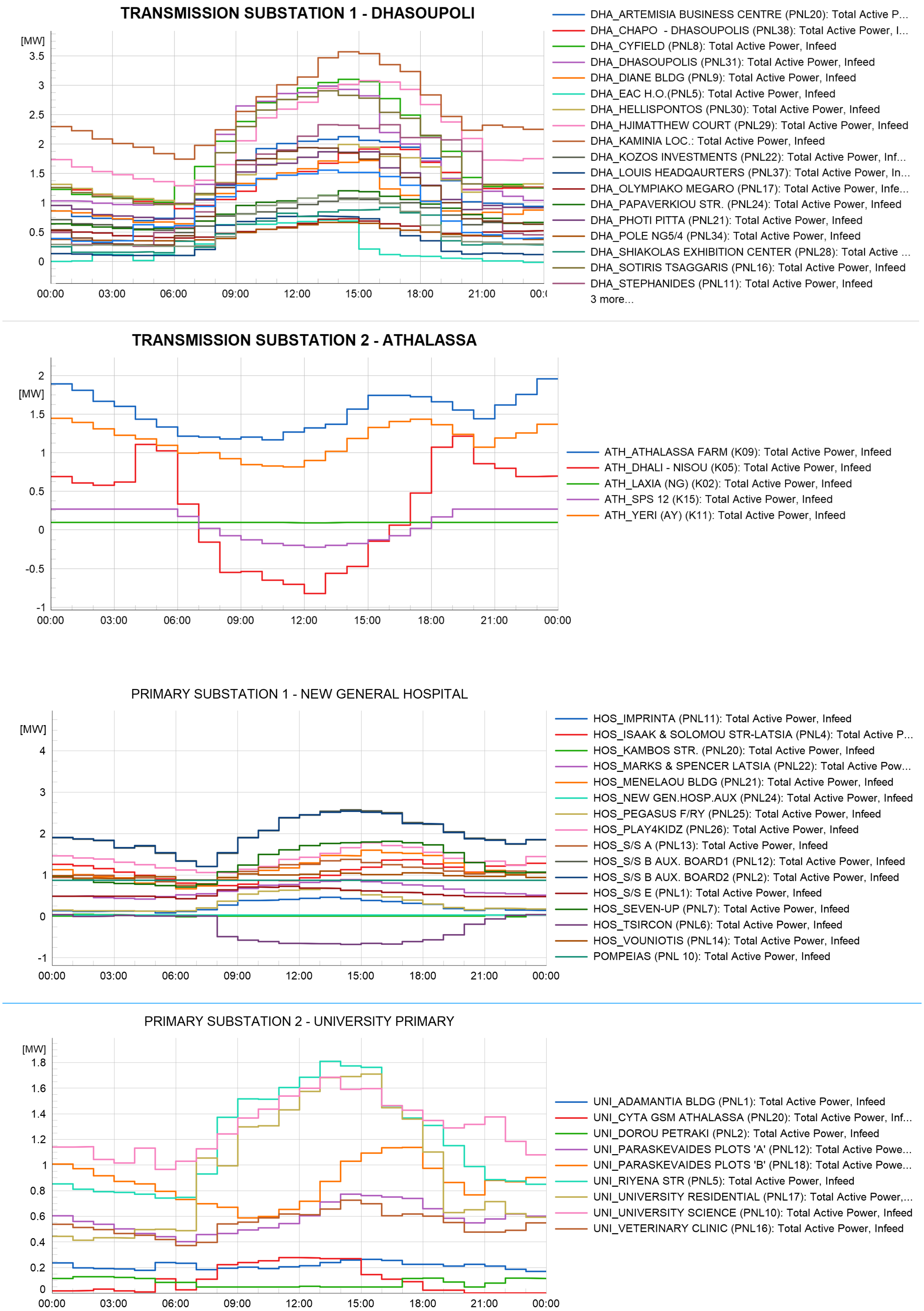

Figure 12. Daily average power profiles of the Case Study power network for the Reference Scenario.

In order to evaluate the impact of the current EVCP penetration levels (public and private), a power flow analysis has been performed for Case Study power network. As showcased in the following Figures, the analysis focuses on the power loading of each individual transformer and feeder, the loading of the tie lines as well as the voltage level of each busbar.

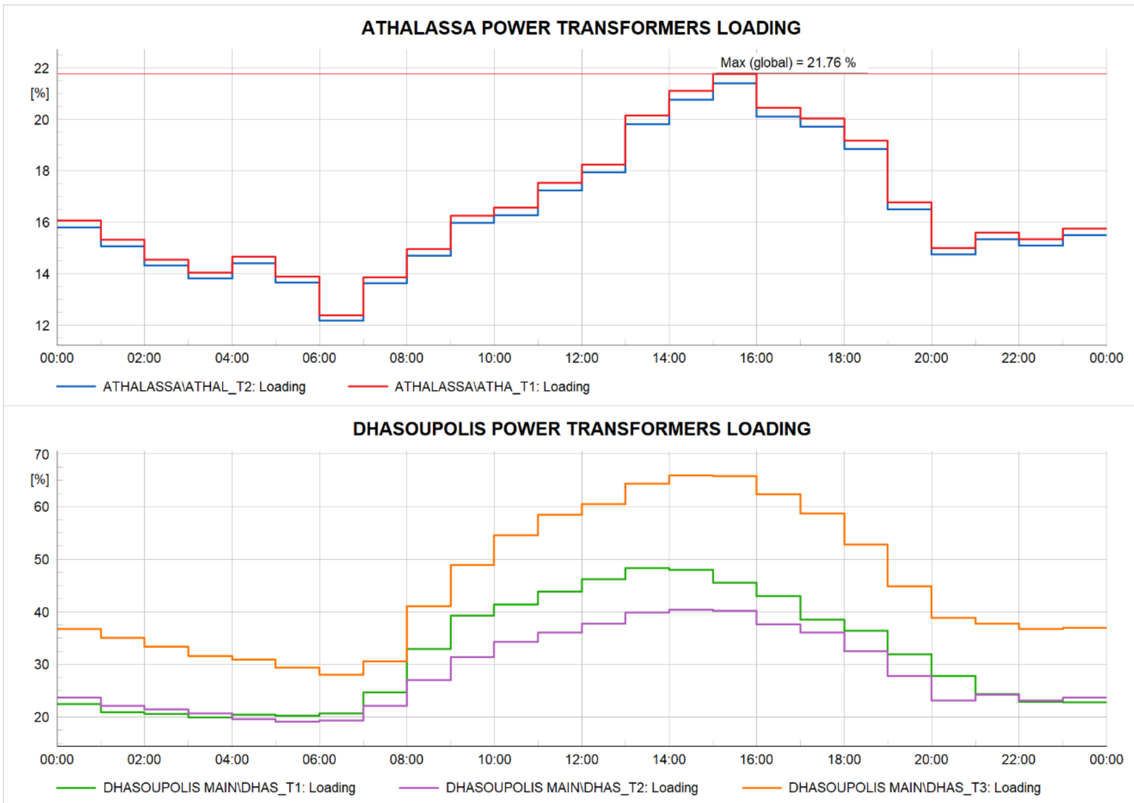

Figure 13. Power Loading of the Primary S/S Transformers consisting of the Case Study power network for the Reference Scenario.

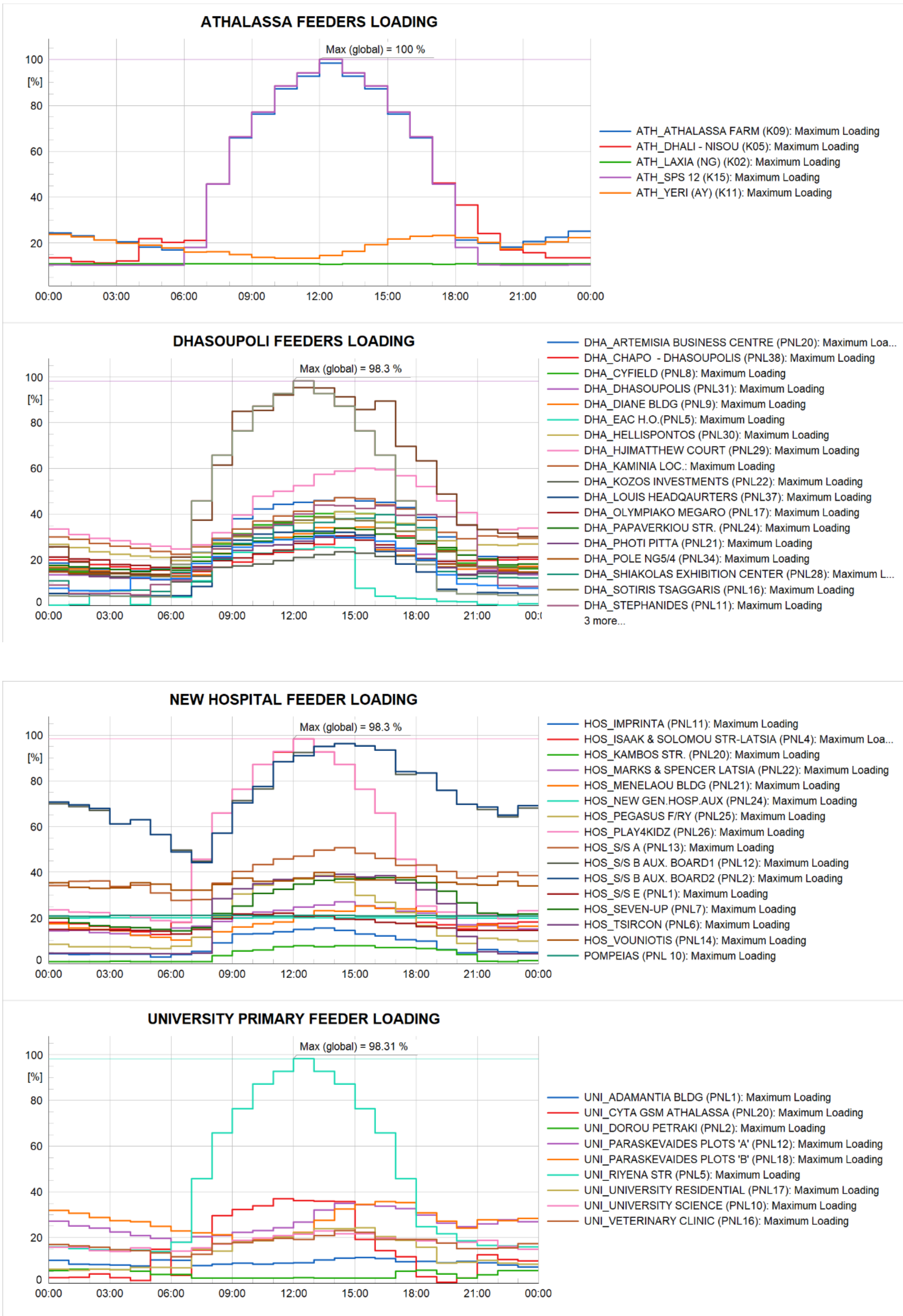

Figure 14. Feeder Loading of the S/Ss consisting of the Case Study power network for the Reference Scenario.

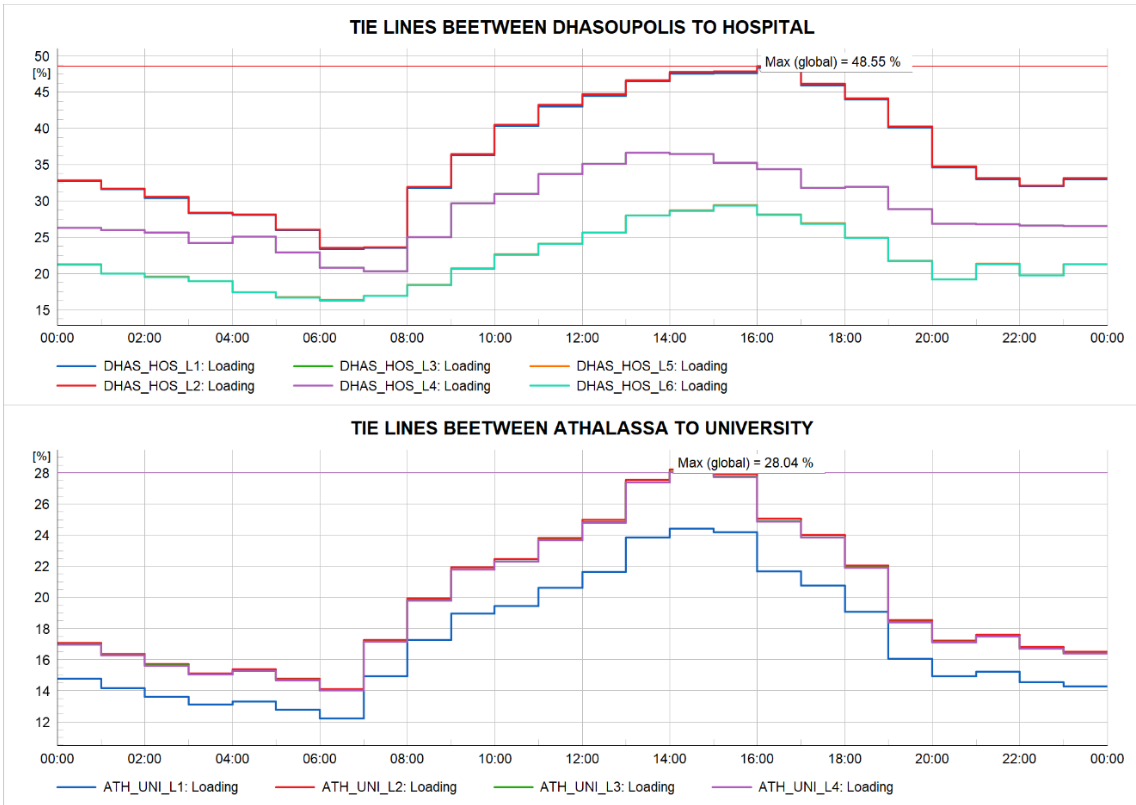

Figure 15. Tie Lines' Loading of the S/Ss consisting of the Case Study power network for the Reference Scenario.

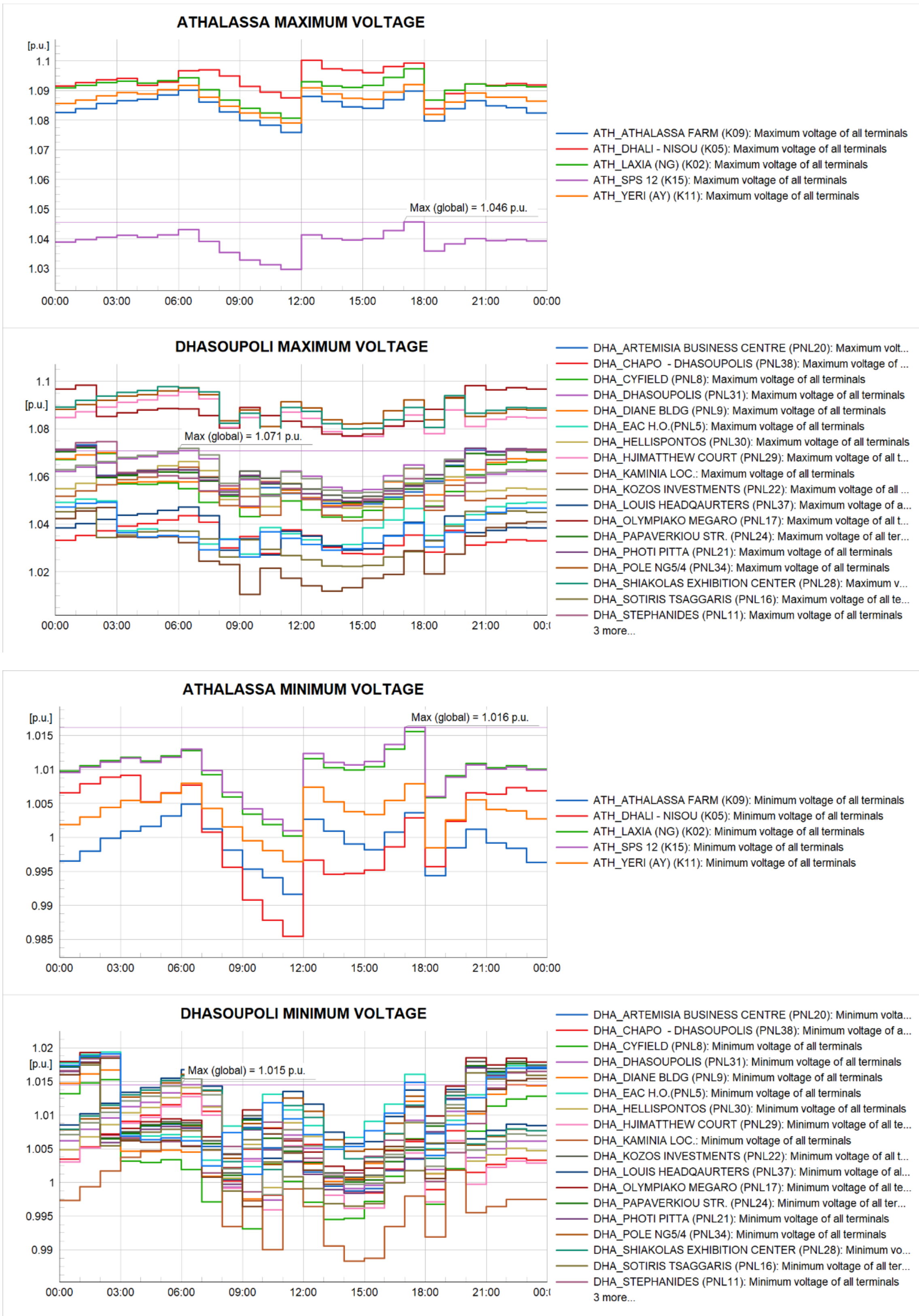

Figure 16. Busbar Voltage Levels of the S/Ss consisting of the Case Study power network for the Reference Scenario.

As clearly demonstrated in the above Figures, that Case Study distribution network operates well within the nominal limits in terms of power loading and voltage levels. Although in some busbars the voltage levels reach their threshold of 1.1 pu (Figure 16) due to peak hours of PV generation, this is addressed locally by the inverter settings and thus any potential violation of grid constraints is alleviated.

Based on the results, it is concluded that the current penetration level of both public and private EVCPs is extremely low and does not have any impact on the distribution system of Cyprus. To this end, and bearing in mind the available technologies of the current EVCP infrastructures (lack of smart control or V2G capabilities) as well as the present unavailability of market price signals, there is no flexibility potential for the Reference Scenario.

4.2. Future Scenario – Year 2028

This Scenario follows the methodology and the assumptions presented in Section 3 by which EVCP can both charge and discharge (flexibility provision) through established V2G capabilities.

For easier reading of this Report, it is recalled that three periods are identified: Winter Season (SC1), Middle Season (SC2) and Summer Season (SC3), while five different EV charging approaches are investigated.

4.2.1. Impact of EVCP integration on the Cyprus' Power System and the Total Cost (the TSOC perspective)

From the perspective of the TSOC, the obtained results concern the impact on the whole power system of Cyprus and the corresponding total system cost. To this end, the comparison is presented in terms of the following indicators:

- Generation cost of the system (€)
- Generation cost of the system (€/MWh)
- RES generation (GWh)
- RES curtailments (MWh)

The following Tables summarize the results for each one of the identified Seasons as well as the average Annual results, in contrast to the Charging Scenarios.

Table 7. Comparative for a typical day of Winter Season (SC1).

Parameter	CS1-BaU	CS2	CS3	CS4	SC5
Total System Cost (Thousand €)	3767	3766	4183	4060	4062
Total CO_2 Cost (Thousand €)	1037	1037	1180	1110	1114
Total Fuel Cost (Thousand €)	2670	2670	2944	2885	2885
Total System Cost (€/MWh)	310.2	310.2	318.9	311.2	311.2
Total CO_2 Cost €/MWh)	85.4	85.4	90.0	85.1	85.3
Total Fuel Cost €/MWh)	220	220	224	221	221
Total CO_2 Emissions (Tones)	12889	12878	14662	13794	13835
Total Demand (MWh)	15300	15297	17629	17650	17658
RES generation (MWh)	3156	3156	4512	4604	4604
RES Curtailment (MWh)	0	0	92	0	0

Table 8. Comparative for a typical day of Middle Season (SC2).

Parameter	CS1-BaU	CS2	CS3	CS4	SC5
Total System Cost (Thousand €)	2519	2503	2919	2671	2676
Total CO_2 Cost (Thousand €)	664	747	783	785	788
Total Fuel Cost (Thousand €)	1811	1718	2090	1847	1849
Total System Cost (€/MWh)	317.2	318.9	321.2	317.3	318.3
Total CO_2 Cost €/MWh)	83.6	95.2	86.2	93.3	93.7
Total Fuel Cost €/MWh)	228	219	230	219	220
Total CO_2 Emissions (Tones)	8250	9279	9729	9755	9791
Total Demand (MWh)	11354	11352	13362	13381	13393
RES generation (MWh)	3413	3503	4275	4963	4987
RES Curtailment (MWh)	507	417	1683	995	971

Table 9. Comparative for a typical day of Summer Season (SC3).

Parameter	CS1-BaU	CS2	CS3	CS4	SC5
Total System Cost (Thousand €)	4909	4908	5073	5019	5025
Total CO_2 Cost (Thousand €)	1381	1381	1422	1400	1417
Total Fuel Cost (Thousand €)	3457	3456	3579	3546	3537
Total System Cost (€/MWh)	302.5	302.6	306.2	302.4	302.9
Total CO_2 Cost €/MWh)	85.1	85.1	85.8	84.4	85.4
Total Fuel Cost €/MWh)	213	213	216	214	213
Total CO_2 Emissions (Tones)	17152	17156	17664	17397	17599
Total Demand (MWh)	20499	20495	23250	23279	23276
RES generation (MWh)	4272	4272	6684	6684	6684
RES Curtailment (MWh)	0	0	0	0	0

Table 10. Comparative for an Annual typical day.

Parameter	CS1-BaU	CS2	CS3	CS4	SC5
Total System Cost (Thousand €)	1266	1265	1380	1335	1337
Total CO_2 Cost (Thousand €)	343	346	388	374	374
Total Fuel Cost (Thousand €)	902	899	972	940	942
Total System Cost (€/MWh)	309	309	315	309	310
Total CO_2 Cost €/MWh)	84	84	88	87	87
Total Fuel Cost €/MWh)	220	219	222	218	218
Total CO_2 Emissions (Tones)	4257	4293	4820	4650	4653
Total Demand (MWh)	5328	5327	6158	6169	6167
RES generation (MWh)	1229	1231	1773	1853	1850
RES Curtailment (MWh)	26	23	151	71	75

The results clearly demonstrate that CS4, which is considered as the best charging scenario where technological advancements are in place and smart charging strategies are followed, not only yields the lowest Total Cost compared to other coordinated strategies (i.e. CS3 and CS5) but also manages to maintain similar Total System Cost levels with the CS1-BaU. This means that the facilitation of proper infrastructure which enables coordinated smart charging shall not create any financial impact to the power system operation and simultaneously it shall be able to adopt large penetration levels of EV and EVCP compared to the Reference Year.

4.2.2. Impact of EVCP integration on the Distribution Network and Local Flexibility Markets (the DSO perspective)

In a similar manner, the distribution network impact is also investigated by utilising the identified Seasons as well as the average Annual results, in contrast to the Charging Scenarios.

As shown in Figure 17, SC3 has a noticeable effect on the maximum feeder loading, while SC1 and SC2 have a relatively small impact compared to the BaU case.

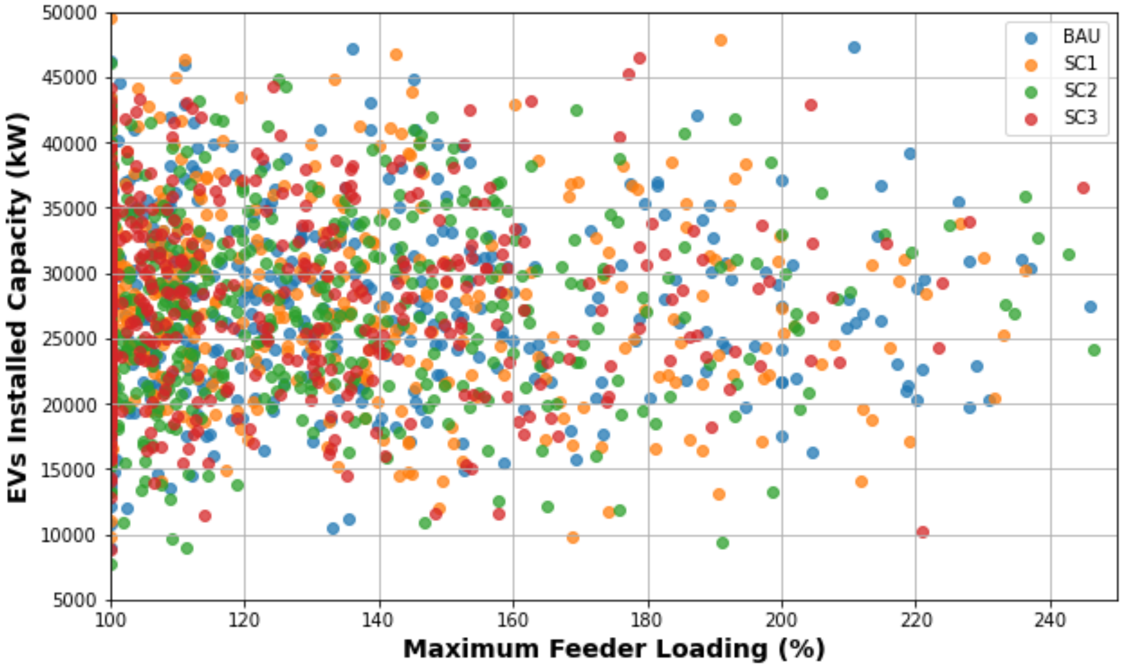

Figure 17. Impact of EVCP penetration on the Maximum Feeder Loading of the Cyprus' power network for the Future Scenario of Year 2028.

Similarly, the impact of the examined charging profiles on the maximum voltage difference at the PCC is minimal. This is due to the fact that the voltage at the PCC is affected by the active power injected at it. Therefore, it can be safely concluded that the EVCPs must be installed in the same area in order to significantly reduce the total inject power to the grid. The impact of the different EVCP penetration levels, under the different charging scenarios, on the maximum voltage difference is depicted in the following Figure.

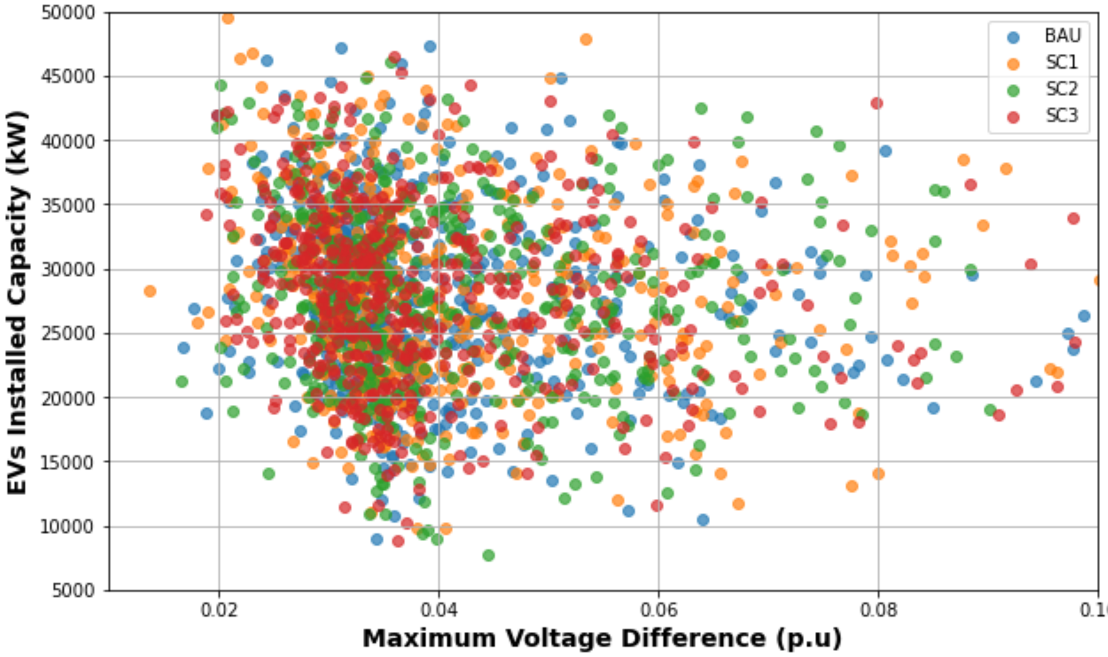

Figure 18. Impact of EVCP penetration on the Maximum Voltage Difference of the Cyprus' power network for the Future Scenario of Year 2028.

It is widely known in the field of power system operation that the N-1 criterion of the transmission system must always be satisfied at all times. The criterion dictates that power flow should be constrained so that a transmission network does not fail in a case of a failure of one of the network's components. Under this rule the failure of a single power line, for example, would not cause power outages. In the scope of this study, the N-1 criterion for all the selected transmission S/Ss has been put to the test. The results highlight that for the case of Dhasoupolis S/S, the maximum allowable power transformer loading is approximately at 63%, while the respective limit for Athalassa S/S is at 50%. It should be noted that substations Hospital and University are primary substations, thus they do not have power transformers and subsequently excluded from the criterion.

As illustrated in the following Figures, even in the case of maximum predicted level of EV penetration, the constrain of maximum transformer loading is always satisfied. This is due to two facts: Firstly, the current S/Ss have a large capacity and secondly, the time of the maximum charging does not coincide with the peak demand of the S/S.

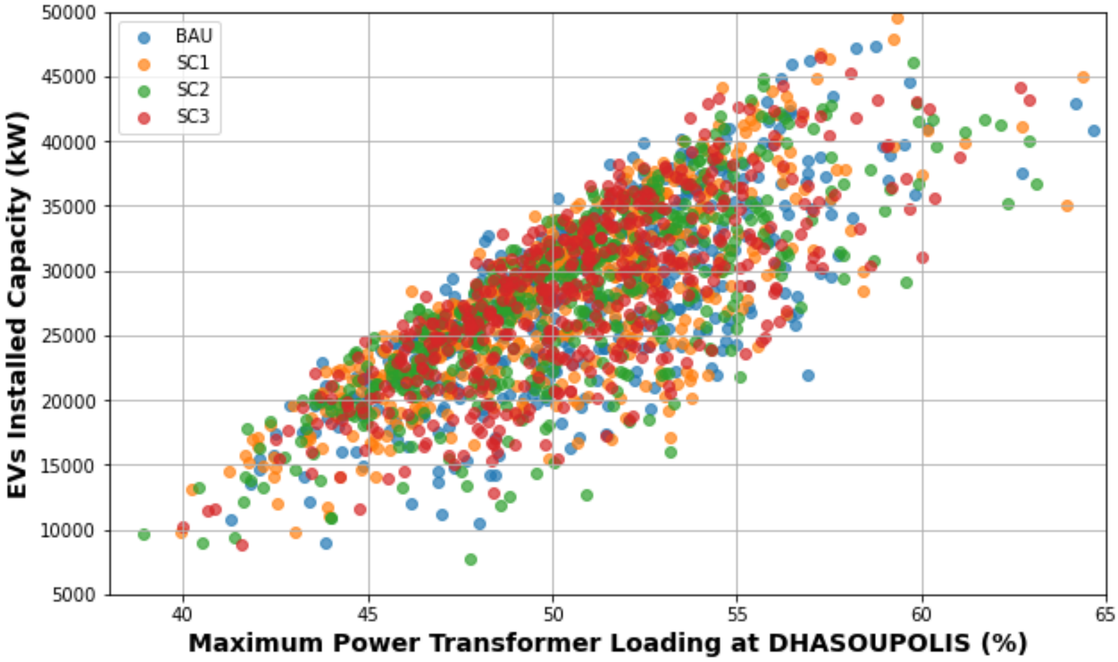

Figure 19. Impact of EVCP penetration on the Maximum Transformer Loading of the "Dhasoupolis" S/S for the Future Scenario of Year 2028.

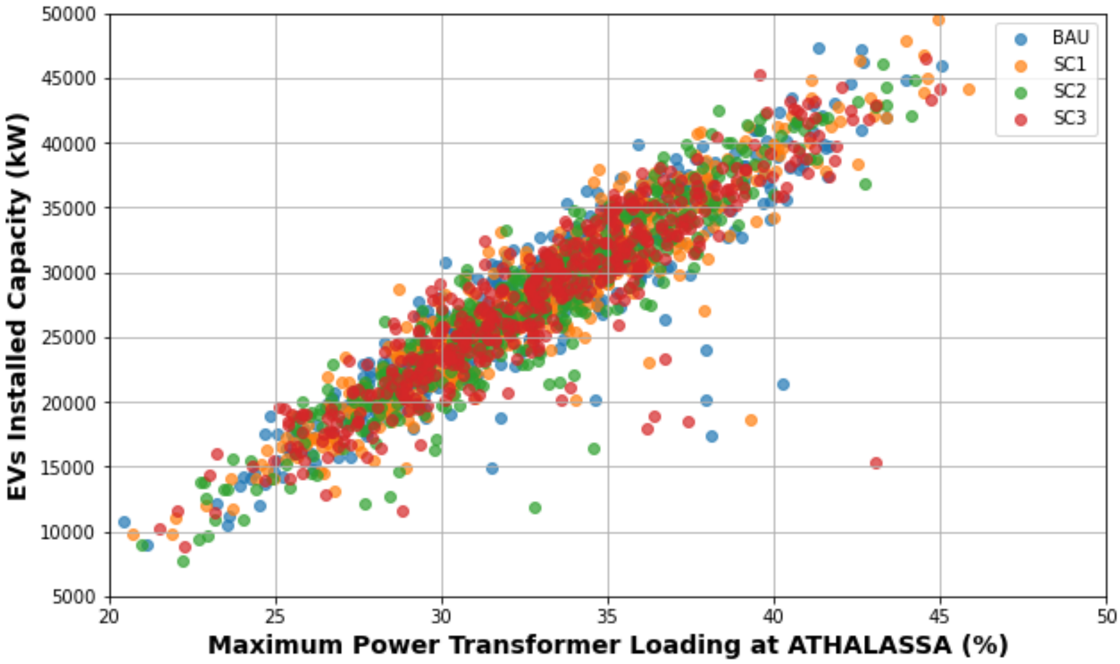

Figure 20. Impact of EVCP penetration on the Maximum Transformer Loading of the "Athalassa" S/S for the Future Scenario of Year 2028.

In terms of Hosting Capacity, the results demonstrate that the SC3 yields the highest potential of Hosting Capacity increase. This is due to the fact that the energy absorbed from the EVs (charging mode) during maximum PV generation is significant compared to the low total load demand of the Cyprus' power system. As depicted in the following Figure, the impact of the expected EV penetration with the V2G capability has a small noticeable impact on Hosting Capacity and it is highly driven by the location of the installed EVCP.

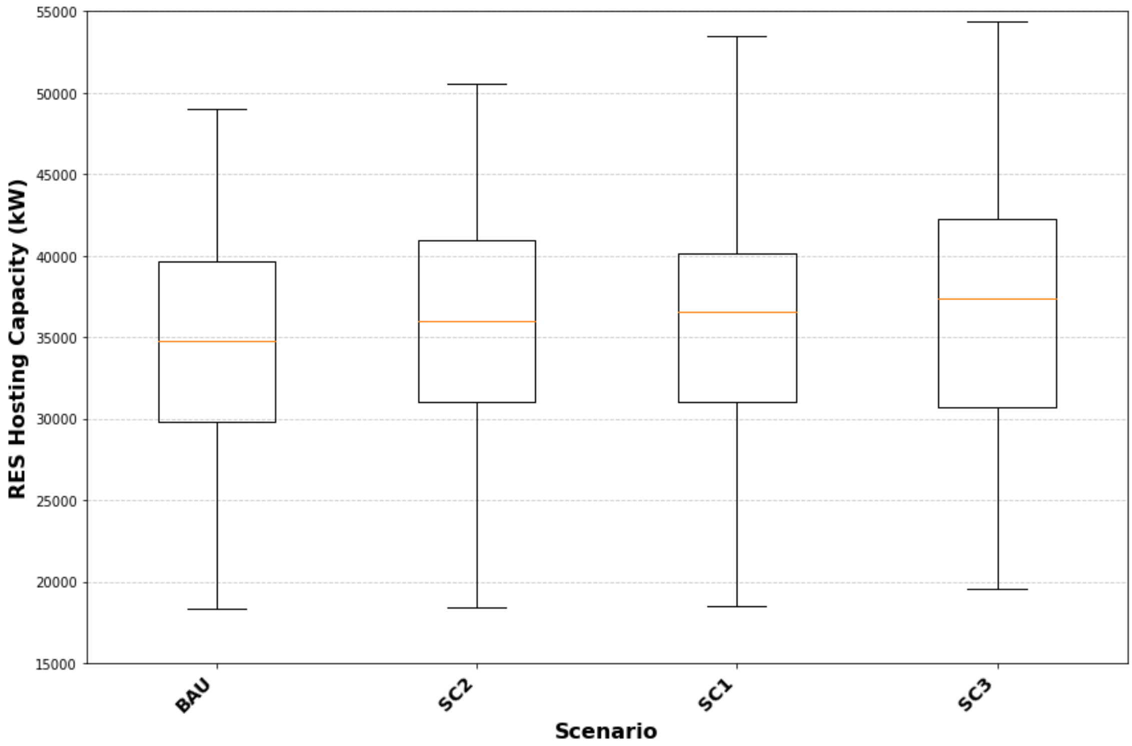

Figure 21. Impact of EVCP penetration on the Hosting Capacity of the Cyprus' power network for the Future Scenario of Year 2028.

In terms of flexibility provision to LFMs and the benefit of EV Owners, this was estimated based on the Methodology and Assumptions presented in Section 3. More specifically, by considering the DSO's Ten-Year Development Plan as well as the assumptions presented in Section 3.4, the Total Expected Grid Investments Costs during the period 2023 – 2034 are yielded to be €570,746,581 (Net Present Value = €498,923,574)[1]. As already stated, only a specific percentage of this cost is associated to investments for congestion avoidance, and it is estimated by exploiting CFs. Based on the identified CFs and the Total Expected Grid Investments Costs, the total investment cost due to congestions has been estimated to €72,417,993 (Net Present Value = €63,222,875) which is approximately 12.6% of the total investments.

Following the simulation results, it is yielded that the average Peak Demand Reduction, occurred due to the flexibility provision of EVCS, is approximately 15%. This leads to the calculation of the following ACFs:

Table 11. Estimated Adapted Congestion Factors for the Future Scenario of Year 2028.

Type of Equipment	Average Peak Responsibility Factor (APR)	Adapted Congestion Factor (ACF)
MV U/H	75.0%	7.01%
MV O/H	80.0%	20.40%
LV U/G	69.0%	5.28%
LV O/H	75.0%	17.21%
PM Transformers	77.0%	11.78%
GM Transformers	72.0%	5.51%

By utilizing the estimated AFCs, the expected grid investment costs by year 2034 (Ten-Year Development Plan) have been reduced to €45,762,813, therefore €26,655,180 are expected grid capital expenditure savings for the DSO.

As described in Section 3.4, in order to estimate the Total Flexibility Energy Units [MWh] required and subsequently the Flexibility Procurement Price [€/MWh] for which the EV owners can be compensated for their EV flexibility, the following

[1] The economic results presented in this study are primarily based on the outcomes of past studies and are therefore considered to be indicative. Achieving higher accuracy would require substantial additional effort, which was not feasible within the given timeframe for delivering all the reporting requirements provisioned by the Regulation.

feeder-related factors were estimated for the two identified Congestion Use Cases.

Table 12. Estimated Feeder-related Factor for Congestion Use Case 1.

	2024	2025	2026	2027	2028
Num. Of Feeders with Overload	8.75	10.06	11.57	13.30	15.30
Num. of Days with Overload	14.73	17.24	20.17	23.60	24.19
Num. Of Hours of Overload	1.94	2.29	2.70	3.19	3.76
Power Reduction Per Feeder (MW)	1.10	1.22	1.35	1.50	1.60

Table 13. Estimated Feeder-related Factor for Congestion Use Case 2.

	2024	2025	2026	2027	2028
Num. Of Feeders with Overload	4.15	4.98	5.97	7.17	8.60
Num. of Days with Overload	8.52	9.71	11.07	12.84	14.90
Num. Of Hours of Overload	1.94	2.29	2.70	3.19	3.25
Power Reduction Per Feeder (MW)	1.10	1.25	1.30	1.55	1.65

Using the abovementioned feeder-related factors and based on internal calculations, the Total Flexibility Energy Units that will be procured by the DSO, within the framework of LFMs, in order to avoid congestion are €7,611,724 (Net Present Value= €6,306,725). Based on further internal calculation (due to its high sensitivity level, the information can not be disclosed), the Flexibility Procurement Price [€/MWh] that the DSO is willing to pay for each unit of Flexibility Energy [MWh], per Flexibility Class, is summarised in the Table below.

Table 14. Estimated Flexibility Energy [MWh] per Flexibility Class for the Future Scenario of Year 2028.

Flexibility Class	Percentage of occurrence [%]	Flexibility Procurement Price [€/MWh]
Critical Flexibility	8	157.99
Normal Flexibility	45	110.67
Non-critical Flexibility	47	94.54

This is the User Cost that each EV owner shall be compensated for the provision of flexibility to the DSO in the context of LFMs. It should be noted that Availability Payments for remaining connected to the distribution network in case of flexibility procurement as well as Flexibility Penalties for failing to provide the requested flexibility volume are not considered in this study.

5. Conclusions, Suggestions and Policy Recommendations

Effective policies and technological advancements will be key to unlocking the full potential of Electric Vehicle (EV) charging infrastructure in contributing to grid stability and renewable energy integration.

The scope of this study is to assess the impact of current and future Electric Vehicle Charging Points (EVCPs) in the power network of Cyprus in terms of electrical flexibility and penetration of Renewable Energy Sources (RES). To this end, a Methodology that is based on the stochastic Monte-Carlo approach has been developed and implemented using an integration of software tools. The applied methodology is divided into two main Scenarios: the Reference Scenario for the year 2023 and the Future Scenario for the year 2028.

The results indicate that the current EV, and subsequently EVCP, penetration levels do not have any noticeable effect on the power system operation for the Reference Scenario of Year 2023, while the available flexibility is insignificant and can not be easily extracted due to the lack of advanced infrastructure.

Concerning the Future Scenario of Year 2028, the findings highlight the best charging scenario, where technological advancements are in place and smart charging strategies are followed, not only yields the lowest Total Cost compared to other coordinated strategies but also achieves to maintain comparable Total System Cost levels with the current national status. This means that the facilitation of proper infrastructure which enables coordinated smart charging shall not create any financial impact to the power system operation and simultaneously it shall be able to adopt large penetration levels of EV and EVCP compared to the Reference Year.

Distribution network impacts were examined in a comparable way, where the results showcase that the analysed charging patterns have a negligible effect on the maximum voltage difference at the PCC as any potential alteration is only driven by the injected active power. Moreover, it is identified that even when the highest expected level of EV penetration is reached, the threshold of maximum transformer loading is consistently met. This can be attributed to two factors: the present oversized capacity of transmission and distribution S/Ss as well as the fact that the time at which the S/Ss reach their maximum charging capacity does not align with the period of highest demand for energy from the S/Ss. The results also demonstrate that the anticipated increase in EV usage, coupled with Vehicle-to-Grid (V2G) technology, has a minimal but discernible effect on Hosting Capacity. This effect is mostly influenced by the strategic geographical distribution of the EVCPs.

In terms of the future flexibility provision of EVCPs, the results highlight that the capital expenditure for distribution networks expected to be reduced by approximately €26,655,180 for the period 2024 – 2034 due to the available EVCP flexibility, while EV owners will have the opportunity to actively participate in the upcoming Local Flexibility Markets (LFMs) and be compensated for Critical Flexibility provision at a Flexibility Procurement Price that is indicatively yielded to be 157.99 €/MWh.

The aforementioned findings were exploited to reach to the following suggestions and policy recommendations for increasing the EV, and subsequently EVCP, penetration levels in Cyprus:

1. EVs and EVCPs can be configured to charge primarily when renewable energy generation is high (e.g., during sunny or windy periods). This can be achieved by proper electricity market signals, time-varying electricity prices or Demand Response schemes as well as other schemes explicitly design for promoting EV market participation. This shall help in absorbing excess renewable energy that might otherwise be curtailed. By storing excess renewable energy in EV batteries and later discharging it during periods of low generation, EVs can act as a buffer, smoothing out the intermittency associated with renewable energy sources like solar and wind, thus increasing the available Hosting Capacity Levels of the Cyprus' power system.

2. The geographical installation of EVCPs, at least the public, should be strategically selected based on the locations with high level penetration of RES systems. This shall lead in reduced potential for voltage increase at the PCC, thus increasing RES hosting capacity.

3. Even though the simulation outcome does not indicate a clear path towards specific recharging types, it is suggested that, at least the public, EVCPs follow the hosting capacity trends.

4. Establish clear regulatory frameworks and market mechanisms to support V2G and G2V deployment. EVs can act as mobile energy storage units that, through V2G technology, can discharge stored energy back to the grid during high demand periods or when renewable energy supply is low. This bidirectional flow of electricity helps stabilize the grid, while creating financial incentives of for the EV owners as well as other related electricity market participants.

5. DSO to develop and maintain an electronic Flexibility Map of the Cyprus' distribution network. This map shall be open to the public and aid EV owners as well as potential ECVP investors to understand the distribution network requirements in both flexibility volumes and time/duration, so that they can feel safer in investing and grasping the available opportunities.

6. It is proposed that there should be no priority in the registration of private or public EVCPs, but it is considered important to create a mandatory register by the DSO in which the exact geographical location and technical characteristics will be available for use by the Policymakers and System Operators.

7. Simplifying the regulatory procedures for setting up EV-related businesses, such as charging stations, can encourage entrepreneurship and investment in the sector. Fast-tracking permits and reducing bureaucratic hurdles can speed up infrastructure development.

8. Public awareness and education campaigns are essential to inform citizens about the benefits of EVs. These campaigns can address common misconceptions, highlight long-term savings, and promote the environmental benefits. Demonstration projects and community events featuring EV test drives can also boost interest and acceptance.

9. Technology standardization and interoperability is suggested to be facilitated. Smart bi-directional charging is proved to be the major driver for increasing hosting capacity, maintaining grid stability, creating revenues for EV owners and stakeholders and most importantly reducing the total cost of the power system. To this end, Policymakers should set and implement industry standards for bi-directional chargers, communication protocols, and grid integration that shall ensure interoperability between different EV models, charging infrastructure and electricity market tools.

By adopting these policies, Cyprus can significantly increase the penetration of EVs and EVCPs, aligning with global sustainability trends. With strategic investments and collaborative efforts, Cyprus can pave the way for a greener, more sustainable future where power system resilience and low electricity costs are established.

6. Acknowledgment

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7. LIST OF ACRONYMS AND ABBREVIATIONS

CERA	Cyprus Energy Regulatory Authority
DER	Distribution Energy Resources
DR	Demand Response
DSO	Distribution System Operator
G2V	Grid-to-Vehicle
LV	Low Voltage
MO	Market Operator
MV	Medium Voltage
NECP	National Energy Climate Plan
PCC	Point of Common Coupling
RES	Renewable Energy Sources
SCADA	Supervisory Control and Data Acquisition
TSOC	Transmission System Operator - Cyprus
V2G	Vehicle-to-Grid