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Economic Value of Flexibility Provided by Power to Gas Conversion Systems in Low-voltage Distribution Grids

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Economic value of flexibility provided by power to gas conversion systems in low-voltage distribution grids

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Abstract

Congestion is widely considered a key challenge in low-voltage (LV) distribution grids due to the high penetration of rooftop photovoltaic (PV) generation. To deal with this problem, LV grids can be upgraded, however, this is a costly solution. Therefore, new approaches are needed to improve the LV grid's flexibility. This paper investigates how power-to-gas (P2G) conversion systems can contribute to enhancing the grid's ability to deal with high levels of solar PV production. To obtain this aim, firstly, dynamic congestion prices as network congestion signals are computed. Then, these prices are utilized as incentives for market participants to invest in P2G systems. In this paper, a mathematical model is proposed to determine the optimal sizing and siting for the installation of P2G conversion systems in LV grids in a way that not only leads to the maximal profit for owners of P2G but also enriches the grid's flexibility. The proposed mathematical model has been formulated using bi-level programming. At the upper level, the owner of P2G systems determines optimal settings of them based on the received incentives from the grid. In addition, the network operator calculates congestion prices at different grid's nodes according to given operation conditions at the lower level. Finally, this model is applied to the typical LV grid within the Dutch power system. The results indicate that market participants are willing to invest in P2G systems after receiving dynamic congestion prices. Furthermore, P2G can reduce the congestion problem in low-voltage grids in case of high penetration of rooftop PV power.

Keywords: Power-to-Gas (P2G), Flexibility, Low voltage distribution Network, Congestion

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Nomenclature

Indices

t	Index for dispatch time.
l	Index for branch (line).
n	Index for busbar.
m	Index for iteration in decomposition approach.
RN	Superscript for renewable resources.
LD	Superscript for load.
min	Superscript for min amount of the variable.
max	Superscript for max amount of the variable.
$\star$	Superscript to show a certain value of variable.

Parameters

N_{line}	Total number of grid's lines.
N_{node}	Total number of grid's nodes.
N_{time}	Simulation period (1 year).
P^{loss}	Active loss price.
P^{shed}	Load shedding price.
P^{curt}	Compensation price for generation curtailment.
S^{max}	Maximum thermal capacity of line.
Q_{PV}^{Cap}	Maximum capacity of PV panel.
$Q^{Det.}, q^{Det.}$	Active and reactive power consumption at each node.
$Q_{Elc}^{max}, Q_{FC}^{max}$	Maximum permissible capacity of electrolyzer and fuel cell.

$C_{Elc}^{Cap}, C_{FC}^{Cap}$	Capital cost of electrolyzer and fuel cell.
$P^{Market}, P^{Market,H2}$	Electricity and hydrogen market price.
R_{line}, X_{line}	Resistance and reactance of the line.
$\eta^{Elc}, \eta^{FC}, \eta^{HS}$	Efficiency of electrolyzer, fuel cell and hydrogen tank.
$EL_{initial}^{HS}$	Initial energy level of hydrogen tank.
$G_a, G_{STD}, G_{Crt.}$	Irradiance of sun, Standard solar irradiance and certain irradiance point.

Set

Θ	Set of variables associated with P2G systems.
Ω	Set of variables associated with Network.
$\hbar(n)$	Set of feeders located after the bus n.
μ, ν	Set of dual variables associated with grid's constraints.
Γ	Optimality cut.

Variables

Q^{loss}, q^{loss}	Ative and reactive power loss.
Q^{shed}	Amount of load shedding.
Q^{curt}	Amount of generation curtailment.
Q^{LD}, q^{LD}	Actual active and reactive power consumption at each node.
Q_{RN}^{E}	Actual output active power of solar panel.
Q^{Line}, q^{Line}	Active and reactive power passing through each line.
Q_{net}	Amount of net load at each node.
$Q^{Cap,Elc}, Q^{Cap,Fc}, Q^{Cap,HS}$	Optimal capacity for electrolyzer, fuel cell, and hydrogen tank.
$Q^{H2,to}, Q^{H2,from}$	Amount of hydrogen injected and absorbed from the hydrogen market.

V	Voltage magnitude of node.
EL^{HS}	Energy state of hydrogen tank.
LB, UB	Lower and upper bounds of the decomposition approach.

1. Introduction

To reach the emission reduction targets of the Paris Climate Agreement [1], many countries deploy more and more renewable-based energy resources in distribution networks. Governments are encouraging end-customers in low voltage (LV) distribution grids to generate renewable energy via supportive schemes such as feed-in tariffs. However, the high penetration of renewable energy sources (RESs) puts more stress on older LV grids which have traditionally been designed to operate passively. Consequently, congestion problem is one of the main challenges in such grids [2]. Since LV grids' feeders have not been built for accommodating high renewable energy, most of them are operating at their maximum capacity during the times of high power injection of distributed renewable energy. In addition, congestion problem would stem from high consumption levels, e.g. related to charging electric cars. Because of these changes in local energy systems, expanding LV grids is one option for accommodating more RESs [3]. However, this solution is costly. Therefore, operators of LV grids are interested in improving flexibility of the network through other likely more efficient methods. In this context, flexibility is defined as ability of the grid to modify the consumption and generation levels at different rates to ensure cost-effective and reliable operation in terms of significant imbalances [4].

Congestion problems in LV grids result from overloading of feeders because of an increase in generation level of renewable energy or consumption level of new electric devices such as heat pumps (HPs). Moreover, congestion problems can be created by voltage rise of grid's nodes as a result of high power injection of local distributed generators (DGs) and low X/R ratio of LV grids' feeders. Recently, various methods have been put forward to solve congestion problems. In general, they can be divided into two main categories, namely indirect and direct approaches [5]. In the indirect or market-based approaches, network operators attempt to change the consumption and generation behaviors of grid's distributed energy resources (DERs) and to increase flexible loads to reduce the network congestion. This can be done by using incentive-based signals. Examples of such methods are dynamic tariffs, direct congestion prices, capacity markets, and flexibility markets. In the capacity market, the capacity of the grid is allocated among aggregators. However, in the flexibility market, network

operators have to buy flexibility services from the market to deal with the congestion problem and it is not necessary for aggregators to buy the grid's capacity. In several cases, indirect approaches are successful in alleviating congestion [2]. However, direct methods such as network configuration, reactive power control, and direct active power control of generation and consumption are used when indirect methods fail. The mentioned approaches are widely applied to local DERs and active loads to solve the congestion problem in LV distribution networks. Nowadays, there is an increasing interest in using hydrogen as fuel in many sectors due to its high gravimetric energy density and potentially crucial role in decarbonization. Thus, an important remaining question is how converting the power generation of RESs into hydrogen can be a solution to the congestion problem in LV grids, which has not been investigated carefully in previous studies.

As known, hydrogen can be produced in several ways. One of the low-carbon methods is Power-to-Gas (P2G), which uses electricity to split water into oxygen and hydrogen. The technical and economic feasibility of using P2G conversion systems in a large scale to absorb surplus generation from renewable resources has been assessed in previous works [6]. However, application of P2G to low voltage grids has not been yet investigated. This paper studies the effectiveness of P2G conversion systems in solving the congestion problem in LV grids. To fulfill this aim, we first propose a new method to determine optimal siting and sizing of P2G conversion systems in LV grids. In the proposed model, distribution congestion prices are used as incentive-based signals to encourage market parties to invest in P2G technologies. Then, we verify to what extent P2G conversion systems can contribute to providing flexibility in LV grids. The mathematical formulation of the proposed model corresponds to bi-level programming problems. At the upper level, owners of P2G systems maximize their profits according to the transferred incentive-based signals from the lower level. In the lower level, a distribution network operator (DNO) performs the optimal power flow in the grid to specify whether the grid suffers from congestion or not. In addition, new dynamic congestion prices based on new settings of P2G conversion system are computed in this level. In the proposed model, distribution congestion prices are considered not only as incentive-based signals for enhancing economic feasibility of investing in P2G conversion systems in LV grids, but also as flexibility indicators of the DNO for modifying the generation and consumption patterns of network's users to deal with congestion. Finally, the effectiveness of the separate operation of electrolyzers and fuel cells in maximizing social welfare at LV grids is compared with the compressed operation of them and batteries in this paper.

This paper is organized as follows. Literature review has been done in section 2. Section 3 describes

the method of research. This section has been comprised of two subsections: the first one explains the proposed model for the expansion of P2G systems in LV grids and the second one introduces the case study of a typical LV grid in the Dutch network. Section 4 shows the results of simulations. Section 5 concludes the paper along with recommendations for future work.

2. Literature Review

As mentioned in the previous section, there has been a growing interest in proposing methods for alleviating congestion in distribution networks. First, we discuss the existing methods in literature for solving congestion in distribution networks. Then, we review the application of P2G conversion systems in power systems. Finally, we state that how this paper seeks to cover the existing gap in this knowledge.

2.1. Congestion management in distribution grids

As expressed previously, indirect and direct approaches are utilized for promoting different DERs and flexible loads to reduce congestion in LV grids. Proposing incentive-based signals such as Distribution Locational Marginal Price (DLMP), and congestion price, optimal energy management of the network, and developing a local flexibility and capacity markets are examples of indirect approaches which have been paid much attention in recent years.

Ghazvini et al. in [7] have verified how dynamic tariffs and daily power-based tariffs in the energy management of flexible loads such as electric vehicles (EVs) and HPs can mitigate congestion in the distribution network. Based on [7], dynamic tariffs cannot solve congestion perfectly; whereas, the combination of dynamic tariffs and daily power-based tariffs is more sufficient for alleviating of congestion in the grid. Authors in [8] have expressed that a combined uniform and nodal pricing mechanism along with utilization of electrical energy storages (EESs) can be an effective solution in reducing congestion, keeping the voltage magnitude at the permissible range, and maximizing social welfare in distribution grids. Distribution congestion prices have been utilized as signals to promote household flexible loads for solving grid's congestion in [9]. According to the findings of this paper, rate of congestion improvement is acceptable; however, it cannot completely solve congestion in the grid. Ref [10] has confirmed that proposing DLMP as dynamic tariff for EVs and HPs at each node can have a positive effect on the flexibility of distribution grids. Likewise, Ref [11] assessed how applying DLMP as incentive-based signal for promoting distributed energy storage, generators, and

microgrids in distribution grids can reduce lines' loading and support voltage magnitude of each node. Since conventional schemes for real-time pricing cannot provide enough incentives for end-customers to reschedule their consumption patterns, a new behavioral real-time pricing mechanism has been reported in [12] not only to cover the existing drawbacks of real-time pricing schemes but also to mitigate congestion in distribution grids.

Authors in [13] have recommended a new method for scheduling of charging and discharging of EVs based on fuel shifting and fuel discharging demand response programs for reducing congestion in the distribution network besides of providing ancillary services. The obtained results proved that the grid's operation flexibility has highly been improved after applying the proposed method and the system can accommodate more distributed generation. Hu et. al. in [14] have taken advantages of the complementarity of multiple energy resources in energy hubs comprised of combined cooling, heating and power (CCHP) units, HPs and renewable generators to reduce congestion in distribution networks. Coupling relationship among energy carriers in this model has provided flexibility for distribution network to accommodate more renewable energies. Moreover, a dynamic energy conversion approach has been utilized in [15] for improving the flexibility and reducing the operating cost of integrated electricity and heating systems in condition of high penetration level of renewable energies.

Besides of proposing incentive-based prices for DERs and suggesting a new method for optimal energy management of the grid for mitigating the congestion, developing of the local market in distribution grids has been interested recently. Due to the high integration level of renewable energy in distribution networks and consequently significant congestion problems in such grids, a local flexibility market named FLECH has been established in Denmark for encouraging local DERs in providing flexibility. See [16]. The proposed market, which is being run in parallel with existing energy markets, brings not only financial gains for the DERs owners but also different flexibility services for the DSO. In addition, it can increase the stability and reliability of both distribution and transmission grids. Similarly, authors in [3] analyzed whether a market-based approach can be an effective solution for empowering DERs toward providing flexibility in German distribution grids in comparison to generation curtailment. Simulation results in [3] declared that more generation from renewable resources can be injected into distribution grids considering market-based provision of flexibility in those networks. In addition, a distribution level flexibility market has been established in [17] for solving congestion in distribution grids. The aforementioned market is operated by DNO and aggregators play as flexibility suppliers which accumulate flexibility from their own end-customers. Due to the importance

of protecting privacy constraints of the grid, decentralized based strategy for local flexibility market clearing has been suggested in [18]. In this method, aggregators which use flexibility of demand-side have been considered as flexibility providers. The obtained results from case studies confirmed that the proposed local flexibility market is effective in solving overloading along with supporting voltage in distribution grids. Likewise, a decentralized local market has been designed for distribution networks in [19] to empower local prosumers towards providing flexibility for the grid. The main advantage of this method is not to require more details of the network data. However, it can approximately alleviate congestion in the grid. Furthermore, authors in [20] have shown how coordinated charging of EVs in distribution networks can be successful in preventing congestion. The coordination between EVs and DNO has been done through a distribution capacity market scheme. It has been demonstrated that the safety operation of distribution grids with low congestion can be achieved based on this method.

In addition to indirect approaches, authors in [21] have proposed a grid congestion management controller to handle directly the active power of DERs such as EESs, EVs, and RESs in distribution grids, which leads to alleviating of congestion and increasing stability of the grid. Furthermore, congestion management in low voltage distribution networks has been done through both direct and indirect approaches in [22]. In this paper, a soft open point as flexible electronic device has been used to solve the congestion problem directly. In addition, DLMP as indirect signal has been offered to EVs to change their charging behaviors in a way that leads to secure and high efficient operation of grid. A hierarchical congestion management approach has been recommended in [23] for mitigating congestion in an active distribution network. In this method, microgrids and direct control resources power flow capabilities and ancillary services supplied by local distributed generators are main sources of relieving congestion in the grid. The results declared that the proposed model has reduced congestion costs of the grid effectively.

2.2. P2G Conversion system

This part tries to review important intentions that lead to an increasing application of P2G conversion system in power systems.

One of the major challenges for relying on 100% renewable energy in power systems is the storage of variable energy generation. Authors in [24] deducted how the storage ability of P2G technologies can pave the way for such energy transition. They showed that the capital expenditure (CAPEX) of P2G needs to be less than 2500 Euro/Kw(el) to make P2G more competitive than Li-ion batteries in energy storage. An optimal power method for the grid-connected large-scale PV system combined with

the hydrogen production system has been suggested in [25] which ensures the stability and security of the grid. In addition, the effect of hydrogen transportation distance on the decision for determining the optimal capacity of the proposed PV-hydrogen system has been evaluated. Multi-objective optimization problem has been suggested in [26] to generate clean hydrogen from a wind-battery-electrolyzer system considering low speed conditions of wind. Results have manifested that the optimal design of the system can reduce the total hydrogen deficit, levelized cost of hydrogen along with the energy dump possibility. A new flexible energy-use mechanism has been presented in [27] among P2G conversion systems, steam methane reforming (SMR) plants, and gas-fired units to compensate the shortage of natural gas, reduce emissions and increase the energy efficiency of interdependent natural gas and electricity networks. Based on the results, methanation of hydrogen cannot be economically competitive and the energy efficiency of the integrated natural gas and electric networks is low in case of converting power to methane. Whereas, application of the proposed energy-use mechanism in such integrated systems can improve efficiency and reduce carbon emissions. Authors in [28] have proposed a coupling model for scheduling an integrated energy system at the northern China industrial park. In this model, jointed operation of carbon capture power plants and P2G facilities has resulted in generating more power from wind turbines and utilizing Co2 as material for P2G technologies instead of storing them. In addition, The optimal scheduling for integrated electricity and gas networks considering hydrogen-based vehicles has been carried out in [29]. According to the results, coordinated operation of EVs and hydrogen-based vehicles can reduce 12.75% of the total operation cost. Technical and economic effectiveness of generating hydrogen through electrolyzers for three different Southern Italian locations have been done in [30]. According to the findings of this paper, for the region which is powered by wind turbines (WTs), generating hydrogen can be the most appropriate business case. In addition, a joint scheduling model has been introduced in [31] for Belgian power and natural gas energy systems to show how P2G conversion systems can boost the link between energy systems. Feasibility study of the photovoltaic-hydrogen energy system has been done in [32]. According to components costs in that paper, the application of such systems can be affordable when the polymer electrolyte membrane (PEM) based technology is selected. The potentials and challenges associated with the role of hydrogen and fuel cells in storing renewable energy in power networks have been summarized in [33]. Furthermore, authors in [34] have reviewed the feasibility of large-scale clean hydrogen generation from both technical and economic points of view.

Development of P2G conversion systems is not limited only for bulk power systems. They can be

utilized as energy supplier in remote areas. Because of the effectiveness of hydrogen in preventing oversize planning of solar panels and batteries, the authors in [35] have designed an energy system with combination of renewable energy resources and hydrogen storage for off-grid communities. They showed that the development of hybrid storage combined with Li-ion batteries and alkaline electrolyzers is an affordable option compared to others for such remote regions. Abdin et. al. in [36] have determined the optimal combination of WTs, photovoltaic (PV) systems, batteries, and electrolyzers for off-grid regions based on minimizing costs of energy. According to the results, the application of electrolyzers results in more economic benefits compared to using of batteries in case of long-term energy storage in off-grid regions. Economic viability of solar power to gas application in geographical islands has been examined in [37]. According to this paper, at the same size hydrogen can provide the seasonable storage compared to batteries in such areas. Arsalis et all [38] developed a small-scale cogeneration system that combined of gas-generation, solar panels, and electrolyzer for application in Cyprus without interconnection to the main grid system. They utilized an electrolyzer to convert the excess power to hydrogen when needed. They concluded that the cost of electricity can reduce more than 60% of the current cost in Cyprus in this model.

Effectiveness of installing P2G in microgrids from technical and economic views has been examined recently. In [39], two-stage robust optimization has been proposed for the optimal operation of cooling-heating and power (CCHP) microgrids considering P2G conversion systems. Compared to the case without P2G systems, the efficiency of the electricity-gas coupling has improved. In addition, the operation cost of the microgrid has reduced due to low natural gas purchases from the natural gas pipeline network. Authors in [40] have assessed the economic and emission efficiency of multi-carrier microgrids considering integrated compressed air and P2G storage technologies. According to the findings of the paper, the development of combined compressed air and P2G systems as energy storage can reduce the operation cost and generated pollution up to 14.2% and 9.6% respectively compared to solely utilization of compressed air energy storage. Finally, authors in [41] have determined the optimal placement of fuel cell plants in medium voltage distribution networks to reduce generation emissions of the grid's substations, voltage fluctuations, and operating costs, while ignoring the investment cost of P2G.

As reviewed, most of studies have attempted to encourage DERs such as flexible loads and energy storage systems in alleviating congestion of distribution grids through incentive-based signals or direct controls. On the other hand, most previous works around P2G conversion systems have been limited

to assess their techno-economic-environmental feasibility on large-scale power systems. In addition, few works are available to assess their effectiveness on microgrids. However, to date, the efficiency of P2G conversion systems in reducing congestion in LV grids has not yet been formally studied. Our paper fills this gap. We explore how P2G conversion systems in LV grid can bring financial gains to their owners as well as the whole society.

3. Method of Research

This section comprises of two subsections. The first section involves three parts. Part 3.1.1 describes how congestion prices can be utilized as indicators of congestion for the DNO. After that, part 3.1.2 proposes a mathematical model determining the optimal siting and sizing of P2G conversion systems in LV grids. Furthermore, subsection **??** describes the solution method. Finally, subsection **??** represents the characteristics of the considered case study and the data on generation and consumption.

3.1. Model

This subsection involves two parts. Firstly, we discuss how a DNO can promote P2G conversion systems to reduce congestion in the grid. Following that, in the second part, we propose a mathematical model specifying the optimal settings of P2G conversion system based on the received congestion prices.

3.1.1. Congestion Prices

In the past, congestion problems in LV grids just resulted from demand increases. However, nowadays, congestion problems occur in LV networks due to both demand increase and high penetration of rooftop photovoltaic (PV) systems. A DNO responsible for the optimal operating of the grid, requires an indicator to demonstrate whether the system suffers from the congestion problem or not. In addition, if the DNO wants to solve the congestion problem of the grid through changing the consumption and generation power of grid's participants, she/he should give an appropriate price signal to them. Congestion prices at different nodes are helpful in addressing the congestion. Therefore, they can be considered as indicators of congestion in the grid. Moreover, the DNO can offer congestion prices as incentive-based price signals for grid's subscribers to manage the congestion based on their reaction. Our paper investigates to what extent P2G conversion systems can be successful in alleviating the congestion problem of LV networks. To fulfill this aim, congestion prices are used for promoting P2G. Hence, it is necessary to compute the congestion prices in the grid at first.

When the operational limits of LV grids are approached, congestion occurs. According to the security constraints of the grid, amount of power passing through each feeder of the grid cannot exceed its maximum thermal capacity (Thermal limit). Furthermore, voltage level of each node must be kept in certain bounds because the equipment of grid and end-customers have been designed to work at a specific voltage range (Voltage Limit). When these constraints are binding at a particular operation time, the congestion prices are non-zero and vary by location. The congestion price is positive once the grid suffers from high consumption level. However, it is negative once amount of surplus generation is considerable in the grid. The DNO can calculate congestion prices at different nodes by solving the optimal power flow (OPF) optimization problem.

In our model, we assume that the DNO seeks to minimize the total network cost while satisfying constraints of the grid. The total network cost comprises of three terms: the cost of active loss, the cost of load shedding, and the cost of generation curtailment. Therefore, the objective function of the proposed OPF problem per dispatch time can be formulated as follows:

$$\text{O.F. = Min Total Costs} = \sum_{l=1}^{N_{line}} P_t^{loss} Q_{t,l}^{loss} + \sum_{n=1}^{N_{node}} P^{shed} Q_{t,n}^{shed} + \sum_{n=1}^{N_{node}} P^{curt} Q_{t,n}^{curt} \tag{1}$$

The first term shows the cost of active loss in the grid ($\sum_{l=1}^{N_{line}} P_t^{loss} Q_{t,l}^{loss}$). Real power loss or active power loss at each line refers to the amount of power that is wasted at each line due to the resistance of that line. Power flows from each line create power loss at that line. Since the ratio of reactance to resistance (X/R) of each line in the distribution grid is low, the total amount of the real power loss can be considerable. In addition, the cost of power loss in the network is compensated by the DNO. Because, the consumers are charged based on their power consumption and the revenue of renewable resources is calculated based on their net output power and consequently the cost of active power loss is remained for the DNO. Thus, it is essential to consider the cost of power loss as part of the optimization problem of the distribution network operator (DNO).

As mentioned, the power loss occurs due to the passing of power through the lines of the grid. Thus, if the required power of each consumer at each node of the network is supplied locally through renewable resources at that node, the amount of power loss reduces due to the reduction of the power passing through each line of the network. However, in the case of more renewable resources connected to the grid, reverse power flow happens in the network. As a result of reverse power flow, the amount of power passing through each line of the network increases, which is similar to the overloading condition

of the network. This even causes an increase in the amount of active power loss in the network. Therefore, the presence of renewable resources in the distribution grids can reduce the network power loss when their presence leads to a reduction of the power passing through the grid lines. However, if their presence causes reverse power flow in the grid lines, the amount of active power loss increases.

The second term of the objective function shows the cost of load shedding in the network. As explained previously, once the consumption level at the particular time is high, it is more likely that the grid lines are operated at their maximum thermal capacity and the grid faces the overloading condition. In this condition, if the amount of passing power through each line exceeds its maximum thermal capacity, the load may be shed because of the thermal limits of the grid lines.

Similar to the overloading condition, once the amount of power generation from the solar panels is high, the grid faces the congestion problem due to binding security constraints of the grid. Indeed, in this circumstance, the grid is not capable to control the surplus generation, which consequently causes generation curtailment.

The proposed OPF problem involves technical and security constraints of grid. These constraints can be formulated as follows:

$$Q^{LD}_{t,n} - Q^{E}_{RN_{t,n}} = Q^{Line}_{back_{t,l_n}} - \sum_{l \epsilon \hbar(n)} Q^{Line}_{ahead_{t,l}} + Q^{loss}_{t,l} \tag{2}$$

$$q^{LD}_{t,n} - q^{E}_{RN_{t,n}} = q^{Line}_{back_{t,l_n}} - \sum_{l \epsilon \hbar(n)} q^{Line}_{ahead_{t,l}} \tag{3}$$

$$(V^{back}_{t,l_n})^2 - (V^{ahead}_{t,l_n})^2 = 2R_{Line,l}Q^{Line}_{t,l} + 2X_{Line,l}Q^{Line}_{t,l} + R_{Line,l}Q^{Loss}_{t,l} + X_{Line,l}q^{Loss}_{t,l} \tag{4}$$

$$(V^{min}_{t,n})^2 \leq (V_{t,n})^2 \leq (V^{max}_{t,n})^2 \tag{5}$$

$$Q^{Line}_{l,t} + q^{Line}_{l,t} \leq \sqrt{2} S^{max}_{l} \tag{6}$$

$$Q^{Line}_{l,t} - q^{Line}_{l,t} \leq \sqrt{2} S^{max}_{l} \tag{7}$$

$$-Q^{Line}_{l,t} + q^{Line}_{l,t} \leq \sqrt{2} S^{max}_{l} \tag{8}$$

$$-Q_{l,t}^{Line} - q_{l,t}^{Line} \leq \sqrt{2} S_l^{max} \tag{9}$$

$$Q_{t,n}^{LD} + Q_{t,n}^{shed} = Q_{t,n}^{Det.} \tag{10}$$

$$Q_{RN_{t,n}}^{E} + Q_{t,n}^{curt} = Q_{t,n}^{RN} \tag{11}$$

$$Q_{t,l}^{loss} = R_{Line,l} \frac{(Q_{t,l}^{Line})^2 + (q_{l,t}^{Line})^2}{(V_{t,l_n}^{ahead})^2} \tag{12}$$

$$q_{t,l}^{loss} = X_{Line,l} \frac{(Q_{t,l}^{Line})^2 + (q_{l,t}^{Line})^2}{(V_{t,l_n}^{ahead})^2} \tag{13}$$

Equations (2) and (3) refer to the active and reactive power balance constraints at each node. Equation (4) demonstrates the voltage drop at each particular line of the network. The next constraint illustrates that the voltage magnitude of each node must be kept within the permissible bound. The next four equations show the limitation on the amount of power passing through each line. This amount must be less than the line's maximum permissible capacity. Equations (5)-(9) are known as security constraints of the grid. Equation (10) shows that sum of the actual consumption power and the amount of the load shedding due to the redispatch at each node must be equal to the initial required demand. In addition, equation (11) implies that the sum of the permitted injected power from the PV panels to the grid and the amount of generation curtailment is equal to the expected generation power of them. The last two equations show the amount of active and reactive power loss at each line, which is related to the amount of active and reactive power passing through that line. As can be seen, these equations are non-linear and make the model non-convex. The first-order Taylor series approximation has been used to linearize them in this model by removing second and higher terms as follows:

$$Q_{t,l}^{loss}(\mathbf{Q_t^{net}}, \mathbf{q_t^{net}}) \approx Q_{t,l}^{loss}(\mathbf{Q_t^{net^\star}}, \mathbf{q_t^{net^\star}}) + \sum_n \frac{\partial Q_{t,l}^{loss}}{\partial Q_{t,n}^{net}}(Q_{t,n}^{net} - Q_{t,n}^{net^\star}) + \sum_n \frac{\partial Q_{t,l}^{loss}}{\partial q_{t,n}^{net}}(q_{t,n}^{net} - q_{t,n}^{net^\star}) \tag{14}$$

$$q_{t,l}^{loss}(\mathbf{Q_t^{net}}, \mathbf{q_t^{net}}) \approx q_{t,l}^{loss}(\mathbf{Q_t^{net^\star}}, \mathbf{q_t^{net^\star}}) + \sum_n \frac{\partial q_{t,l}^{loss}}{\partial Q_{t,n}^{net}}(Q_{t,n}^{net} - Q_{t,n}^{net^\star}) + \sum_n \frac{\partial q_{t,l}^{loss}}{\partial q_{t,n}^{net}}(q_{t,n}^{net} - q_{t,n}^{net^\star}) \tag{15}$$

where $Q_t^{net} = Q_{t,n}^{LD} - Q_{RN_{t,n}}^{E}$ and $q_t^{net} = q_{t,n}^{LD} - q_{RN_{t,n}}^{E}$. In the above constraints, $Q_t^{net^\star}$ and $q_t^{net^\star}$ are considered as feasible power flow solutions which are calculated externally and added as a center point for the Taylor approximation. In addition, partial derivatives of total loss to net consumption of each node can be computed based on the loss factors of distribution grid as follows [42]:

$$\frac{\partial Q_l^{loss}}{\partial Q_{t,n}^{net}} = \Big[2Q_l^{Line}\frac{\partial Q_l^{Line}}{\partial Q_{t,n}^{net}} + 2q_l^{Line}\frac{\partial q_l^{Line}}{\partial Q_{t,n}^{net}}\Big]\frac{R_{Line,l}}{(V_n)^2} \tag{16}$$

$$\frac{\partial Q_l^{loss}}{\partial q_{t,n}^{net}} = \Big[2Q_l^{Line}\frac{\partial Q_l^{Line}}{\partial q_{t,n}^{net}} + 2q_l^{Line}\frac{\partial q_l^{Line}}{\partial q_{t,n}^{net}}\Big]\frac{R_{Line,l}}{(V_n)^2} \tag{17}$$

$$\frac{\partial q_l^{loss}}{\partial Q_{t,n}^{net}} = \Big[2Q_l^{Line}\frac{\partial Q_l^{Line}}{\partial Q_{t,n}^{net}} + 2q_l^{Line}\frac{\partial q_l^{Line}}{\partial Q_{t,n}^{net}}\Big]\frac{X_{Line,l}}{(V_n)^2} \tag{18}$$

$$\frac{\partial q_l^{loss}}{\partial q_{t,n}^{net}} = \Big[2Q_l^{Line}\frac{\partial Q_l^{Line}}{\partial q_{t,n}^{net}} + 2q_l^{Line}\frac{\partial q_l^{Line}}{\partial q_{t,n}^{net}}\Big]\frac{X_{Line,l}}{(V_n)^2} \tag{19}$$

After replacing equations (12) and (13) with (14) and (15), the proposed OPF model becomes convex, which guarantees the existence of optimality. According to the defined objective function, the shadow price of active power balance constraint comprises of the marginal loss component and the congestion component. Consequently, the congestion price at each node can be computed by subtracting the marginal loss component from the shadow price of active power balance constraint ($\lambda_{t,n}$) as follows:

$$P_{n,t}^{Congestion} = \lambda_{t,n} - P_t^{loss}\sum_l \frac{\partial Q_{l,t}^{loss}}{Q_{t,n}^{net}} \tag{20}$$

The computed congestion price at each node is considered as the price-signal to promote P2G conversion systems to be operated in that node. As discussed, the amount of congestion price is positive in case of load shedding in the grid, while it becomes negative in case of generation curtailment. The next subsection discusses how the congestion prices as price signals of the grid can have a positive effect on promoting market participants in investing on the P2G conversion systems in LV grids.

3.1.2. Optimal siting and sizing of P2G

In this subsection, a new mathematical model is proposed to find the optimal place and size for installing P2G conversion systems in LV grids. In context of the proposed mathematical model, a strategic owner of P2G conversion systems seeks to assess whether her/his investment on such tech-

nologies in LV grids brings financial gains or not. To address this, she/he needs to predict electricity and hydrogen market prices accurately. In addition, in the proposed model, the congestion price at each node is added to the electricity market price. In fact, the electric consumption price of P2G system at each node is equal to the sum of electricity market price and the congestion price at that node. Hence, the owner of P2G determines her/his optimal decisions regarding the input prices. Moreover, the DNO computes congestion prices at different nodes along with minimizing the total network cost for each operational dispatch interval according to a given generation and consumption status of the grid and the new operation settings of P2G systems. After that, the updated congestion prices are transferred into optimization problem of P2G owner to make new decisions. This kind of mathematical model, which involves two different optimization problems with different objective functions, can be formulated as a bi-level optimization problem. The proposed bi-level model comprises of two levels. In the upper level, the investment and operation settings of P2G conversion systems are specified in a way that maximize the annual profit for owners of them. Furthermore, according to a given generation and consumption status and the operation settings of P2G conversion systems, the DNO computes the network cost along with determining congestion prices at different nodes in the lower level. Fig. 1 shows the structure of the proposed bi-level mathematical model schematically.

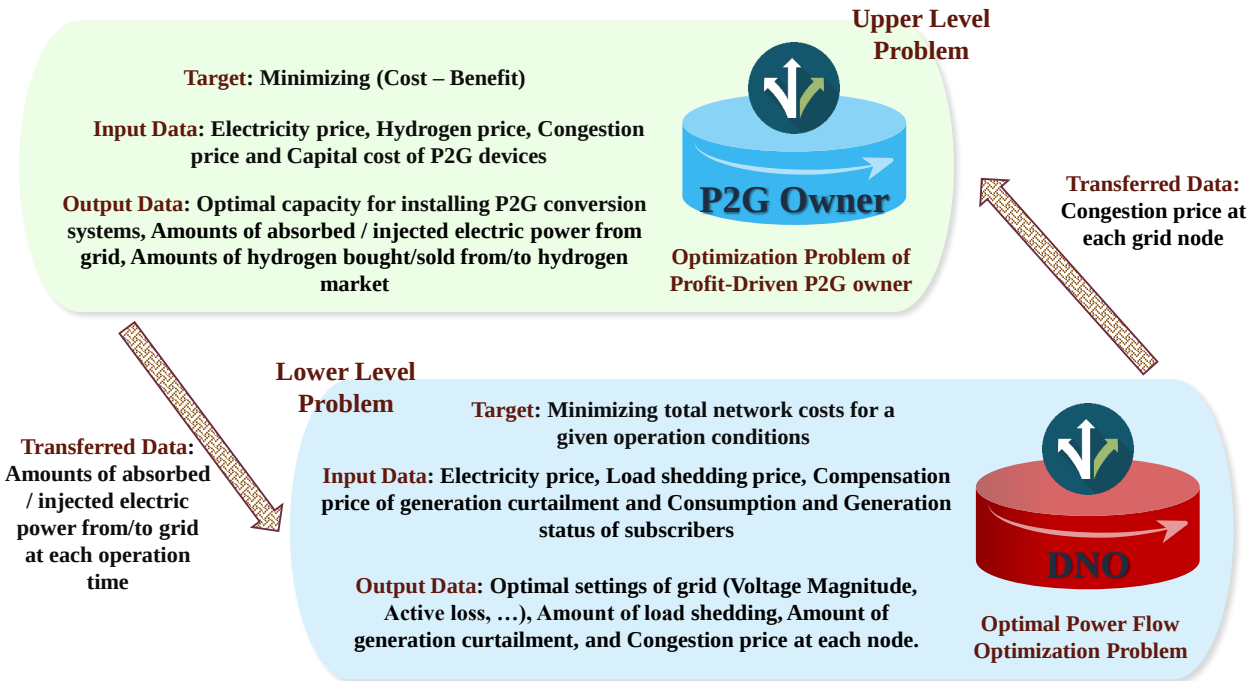


Figure 1: The structure of the proposed bi-level mathematical model

P2G conversion system can comprise of three components: an electrolyzer for converting electric power to hydrogen, a fuel cell for generating electric power from hydrogen, and a hydrogen tank. In this model, two different options are considered for P2G conversion system. In the first option, electrolyzers and fuel cells can operate separately. (See Fig. 2)

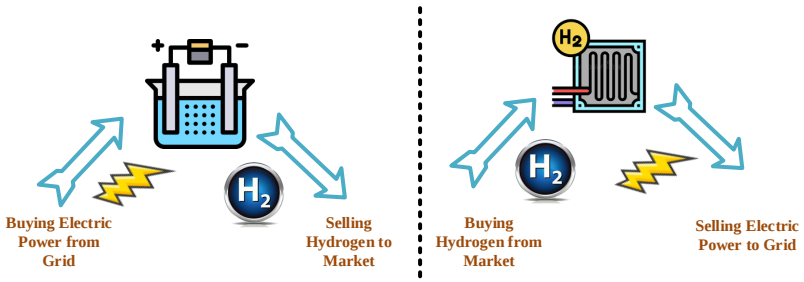


Figure 2: Schematic of the separated option

In this option, electrolyzers and fuel cells can trade hydrogen with the hydrogen market, in addition, the transportation infrastructure is assumed to be feasible to carry hydrogen. The objective function for this option is formulated as follows:

$$
\begin{aligned}
&O.F. = \text{Min: Annual P2G cost - Annual P2G benefit} = \\
&\sum_{n=1}^{N_{node}} Q_n^{cap,Elc} \times C_{Elc}^{Cap} + \sum_{n=1}^{N_{node}} Q_n^{cap,FC} \times C_{FC}^{Cap} \\
&+ \sum_{n=1}^{N_{node}} \sum_{t=1}^{Ntime} Q_{n,t}^{Elc} \times (P_t^{Market} + P_{n,t}^{Congestion}) - (Q_{n,t}^{H2,to} P_t^{Market,H2}) \\
&+ \sum_{n=1}^{N_{node}} \sum_{t=1}^{Ntime} Q_{n,t}^{H2,from} \times (P_t^{Market,H2}) - \sum_{n=1}^{N_{node}} \sum_{t=1}^{Ntime} Q_{n,t}^{FC} \times (P_t^{Market} + P_{n,t}^{Congestion})
\end{aligned}
\tag{21}
$$

The first and second terms in equation (21) refer to the annualized capital cost for electrolyser ($Q_n^{cap,Elc} \times C_{Elc}^{Cap}$) and fuel cell ($Q_n^{cap,FC} \times C_{FC}^{Cap}$) at each node. The third term demonstrates the cost of buying electric power from the grid at each operation time for the electrolyzer and the next term refers to the obtained profit from selling hydrogen to the hydrogen market. The fifth term shows the cost of buying hydrogen from the hydrogen market and the benefit obtained from selling electric power to the grid through the fuel cell is shown in the next term. Constraints of the proposed mathematical model can be expressed as follows:

$$
Q_{n,t}^{H2,to} = \eta^{Elc} Q_{n,t}^{Elc} \tag{22}
$$

$$0 \le Q_{n,t}^{Elc} \le Q_{n}^{cap,Elc} \tag{23}$$

$$0 \le Q_{n}^{cap,Elc} \le Q_{Elc}^{max} \tag{24}$$

$$Q_{n,t}^{FC} = \eta^{FC} Q_{n,t}^{H2,from} \tag{25}$$

$$0 \le Q_{n,t}^{FC} \le Q_{n}^{cap,FC} \tag{26}$$

$$0 \le Q_{n}^{cap,FC} \le Q_{FC}^{max} \tag{27}$$

$$\begin{aligned} &[P_{1,t}^{Congestion}, P_{2,t}^{Congestion}, ..., P_{n,t}^{Congestion}] \in \\ &\text{argmin}\Bigg\{ \sum_{l=1}^{N_{line}} P_{t}^{loss} Q_{t,l}^{loss} + \sum_{n=1}^{N_{node}} P^{shed} Q_{t,n}^{shed} + \sum_{n=1}^{N_{node}} P^{curt} Q_{t,n}^{curt} \\ &\text{Subject to:} \\ &\text{Power flow constraints: Eqs: (2) - (11), (14) - (15)} \Bigg\} \end{aligned} \tag{28}$$

Equation (22) shows the amount of hydrogen generated from the electrolysis of water and the amount of electric power consumption of ($Q_{n,t}^{Elc}$). Equation (23) implies that the power taken from the grid cannot be more than the maximum capacity of the electrolyzer at each node. Finally, equation (24) considers the maximum cap for installing electrolyzer at each node. Similar constraints have also been regarded for fuel cell at each node through equations (25)-(27). The last constraint implies that the congestion prices are calculated based on the OPF problem in the lower level of the mathematical model and then are transferred into the upper level as input parameters.

In the next option, electrolyzers and fuel cells cannot operate separately and they are connected to each other through hydrogen tanks. A compressed unit is considered for operating P2G conversion system at each node. (See Fig. 3)

As seen from Fig. 3, hydrogen generated by electroyzers is stored in the hydrogen tank and it cannot be injected into pipelines. Then, the stored hydrogen can be used by fuel cells for generating

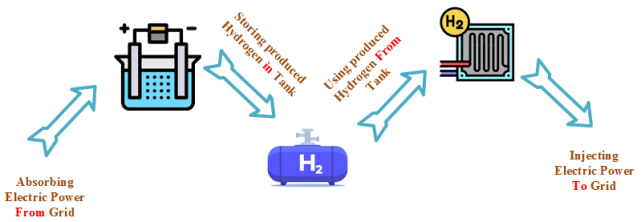


Figure 3: Schematic of the compressed option

electric power when the electricity price is high enough for promoting the fuel cell to be operated. Thus, the objective function of this option along with related constraints can be formulated as follows:

$O.F.$ = Min: Annual P2G cost - Annual P2G benefit =

$$\sum_{n=1}^{N_{node}} Q_n^{cap,Elc} \times C_{Elc}^{Cap} + \sum_{n=1}^{N_{node}} Q_n^{cap,FC} \times C_{FC}^{Cap} + \sum_{n=1}^{N_{node}} Q_{n,HS}^{cap} \times P_{HS}^{Cap} + \sum_{n=1}^{N_{node}} \sum_{t=1}^{Ntime} Q_{n,t}^{Elc} \times (P_t^{Market} + P_{n,t}^{Congestion}) - \sum_{n=1}^{N_{node}} \sum_{t=1}^{Ntime} \eta^{FC} Q_{n,t}^{FC} \times (P_t^{Market} + P_{n,t}^{Congestion}) \tag{29}$$

Subject to:

$$EL_{n,t}^{HS} = EL_{n-1,t}^{HS} + (\eta^{HS} Q_{n,t}^{Elc} - Q_{n,t}^{H2,from} / \eta^{HS}) \Delta t \tag{30}$$

$$EL_{n,t=0}^{HS} = EL_{initial}^{HS} \tag{31}$$

$$0 \leq EL_{n,t}^{HS} \leq Q_{n,HS}^{cap} \tag{32}$$

Electrolyzer and Fuel cell constraints: Eqs: (22) - (28)

The first and second terms of the objective function show the annualized capital cost of electrolyzer and fuel cell. Annualized capital cost for hydrogen tank is considered in the third term. The next term demonstrates the cost of buying electric power from the grid and the last term expresses the benefit of the compressed unit from selling power to the grid. It is beneficial for the owner of P2G systems to buy electric power when the grid suffers from generation curtailment resulting in a negative congestion price and sell the generated power to the grid during the overloading intervals when the congestion

prices are positive. Equation (30) demonstrates the energy level of the hydrogen tank at each operation time which relates to the amount of injection and absorption of hydrogen at that time and the energy level of the previous dispatch time. The initial energy level of the tank has been shown in equation (31). Finally, constraint (32) implies that the energy level of the hydrogen tank must be kept within the permissible bound according to the maximum selected tank capacity. Other constraints are the same as those considered for the first option.

By solving the mathematical optimization problem, we specify the optimal siting and sizing for the installation of P2G conversion system. Then, we show how the operation of P2G conversion systems contributes to providing flexibility for LV grids. The proposed mathematical bi-level model has been solved through the Benders decomposition technique [43]. More details about the solution method are available in the Appendix A.

4. Results of Simulation

To assess the effectiveness of P2G conversion systems in providing flexibility to LV grids, the proposed mathematical model for expansion of such technologies has been verified on a typical LV grid of the Dutch power system. (More details about the case study and initial parameters of optimization have been provided in the Appendix B.) This section comprises of two subsections. The first subsection shows how the grid with high integration level of PV panels can suffer from the congestion problem without considering P2G conversion system. The next subsection demonstrates the role of P2G technologies in improving the grid's flexibility.

4.1. Congestion in scenario without P2G

In this subsection, we first show how a high penetration of rooftop solar panels can cause a congestion problem in LV grids. Then we compute the congestion price at each node.

4.1.1. Generation Curtailment

In this model, the maximum installed capacity of the solar panel at each household is assumed to be 10 times more than the average power use of that home, because we want to examine the flexibility of the grid in case of high integration level of renewable energies. In this circumstance, it is more likely that congestion occurs at different grid lines due to a high net injection power of PV systems to the grid, which results in overloading of the grid line or violation of the node's voltage. Fig. 4 shows the amount of generation curtailment for the case study at each month.

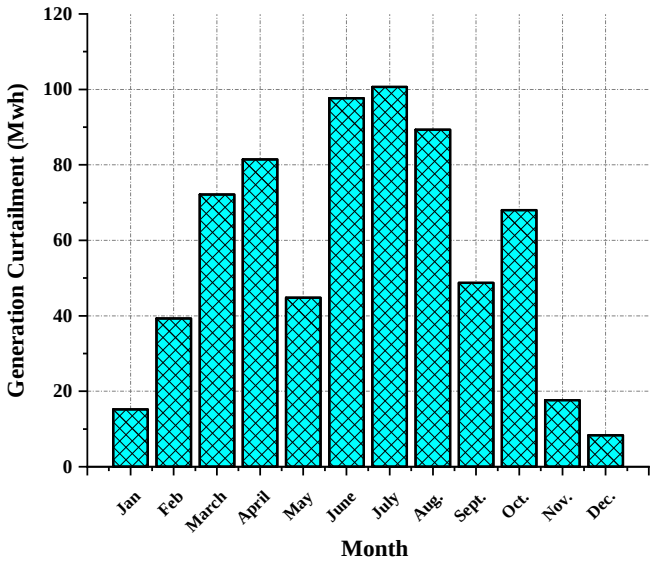


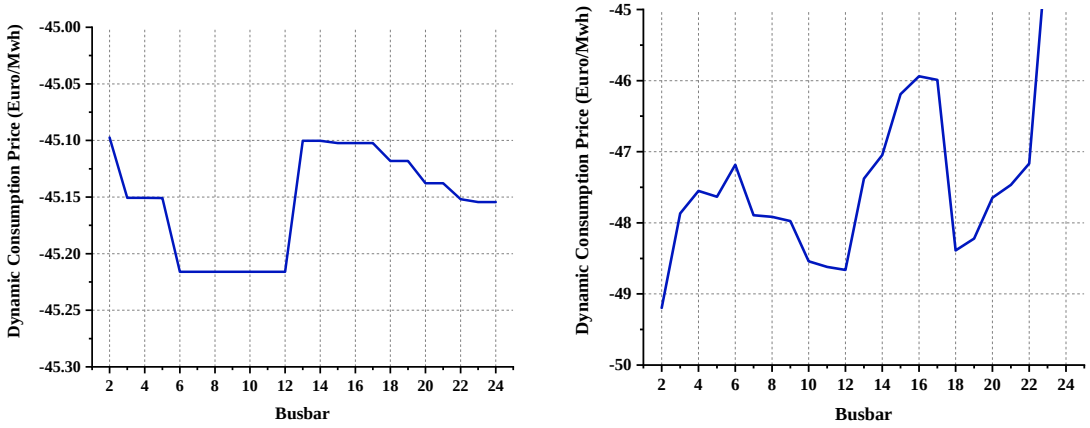
Figure 4: Amount of generation curtailment at each month

As seen from Fig. 4, the amount of generation curtailment is high during the summer. Since the intensity of solar irradiance is high during the summer period, the power production of solar panels is also relatively high. Moreover, according to the results in Fig. 4, the total generation curtailment of the grid per year is 686.06 (Mwh). This amount is significant, implying that the conventional LV grid is not capable to manage the high power production of PV systems. In this case study, the amount of load shedding per year is 1.735 (Mwh). Compared with the amount of generation curtailment, the amount of load shedding is not high. Hence, it is recognized that the congestion problem in LV grids in the future can be resulted from the high integration level of renewable resources besides of an increase in consumption level.

4.1.2. Congestion Prices

Dynamic congestion prices at different nodes can be considered as indicators to show whether LV grids suffer from congestion or not. These prices are non-zero during the times when congestion happens in the grid. Fig. 5 proves this fact by showing the computed congestion prices for different nodes at time 8:00 A.M. and 9.00 A.M. for the specific day in April.

As seen in Fig. 5 the congestion prices are non-zero and vary by location. The non-zero and spatial variability of the congestion prices are attributed to the overloading of the grid lines and violation of the permissible bound for the fluctuation of the nodes' voltage. In addition, a negative price means that high surplus generation is the main reason of congestion in those times at the grid.



(a) 8.00 A.M. (b) 9.00 A.M.

Figure 5: Calculated dynamic congestion prices for different nodes at time 8:00 A.M. and 9.00 A.M.

Fig. 6 shows the maximum amount of the current passing through each grid line along with the permissible maximum capacity at time 8:00 A.M.

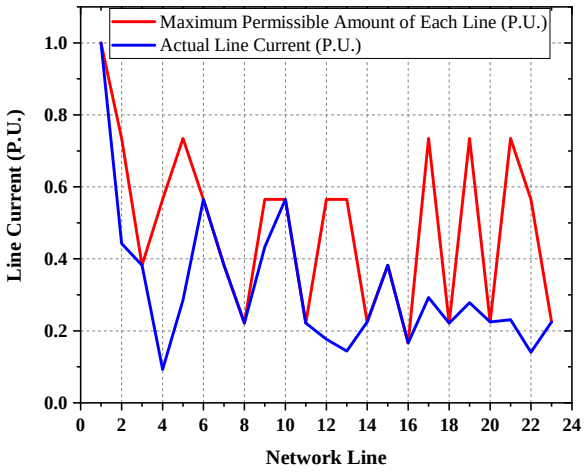


Figure 6: Maximum amount of the current passing through each grid's line at time 8:00 A.M

In fact, Fig. 6 explains why congestion has occurred in the grid. As seen, the current passing through most of the grid lines is the same as their maximum permissible capacity, and passing power more than this amount cannot be valid. Therefore, generation curtailments in the grid happen due to the binding constraint in those lines. As stated, the congestion price at each node is negative and this implies that by increasing the consumption level at each node, the remaining capacity of the lines increases, and consequently the grid would not suffer from the congestion problem at those congested lines.

As depicted in this subsection, the congestion problem in LV grids, which have not been constructed for hosting more generation from distributed energy resources, is undeniable. Thus, it is necessary to propose new methods for reducing the congestion in LV grids such as development of P2G conversion systems.

4.2. Congestion in scenario with P2G

In this part, the optimal location and size for the installation of P2G conversion systems are specified at first. Then, we examine under which condition of congestion, development of P2G conversion systems can be practical. In addition, a break-even point for a given place and capacity of P2G technologies is computed in terms of the needed installation of rooftop solar panels which makes the P2G break even. Finally, in the last part, effectiveness of such conversion systems in providing flexibility for the grid is assessed.

4.2.1. Optimal siting and sizing of P2G conversion systems

As introduced in the previous section, two options for expansion of P2G conversion systems have been considered in this paper. Table 1 presents the optimal location and capacity for installation of electrolyzer and fuel cell which can operate separately (Option 1).

Table 1: Optimal siting and sizing of Electrolyzer and Fuel cell

Node No.	Annual Cost Euro	Annual Profit Euro	Net Revenue Euro	Optimal Capacity Kw
6-Elc	163	164	1	4.00
10-Elc	41	49	8	1.00
11-Elc	100	127	27	2.50
12-Elc	2885	3990	1105	71.75
23-Elc	3634	4433	799	88.00
24-ELC	60	78	18	1.50
11-FC	210	1306	1096	3.50
12-FC	1522	15883	14361	23.75

Table 1 also demonstrates the annual cost and profit for each unit separately. Annual cost comprises of annualized capital cost and operation cost in this simulation. As seen, the net revenue per year for each unit is positive and the total revenue per year obtained from installing the electrolyzer and fuel cell is 17415 Euro. This positive amount for total revenue implies that investment on P2G conversion systems in LV grids can bring financial gains for their owners based on the suggested model in which congestion prices are assumed as incentive-based signals.

Fig. 7 shows how the proposed method can encourage an individual electrolyzer at node 12 to be operated.

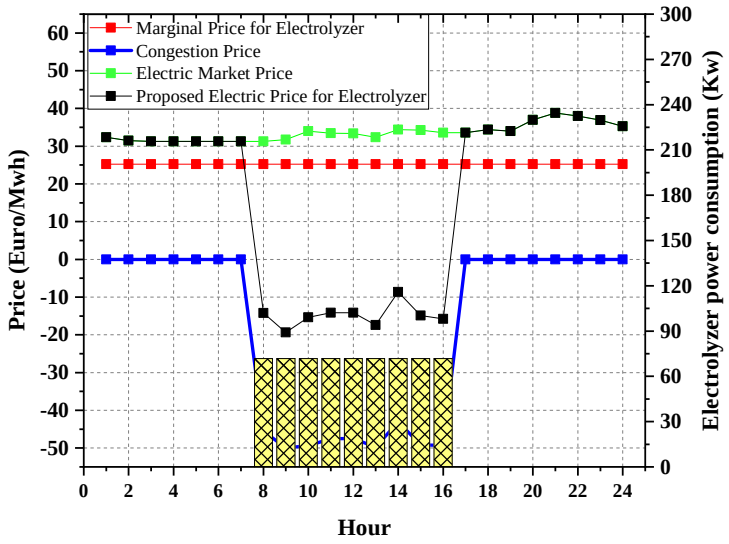


Figure 7: Output power of electrolyzer at node 12 during a particular day

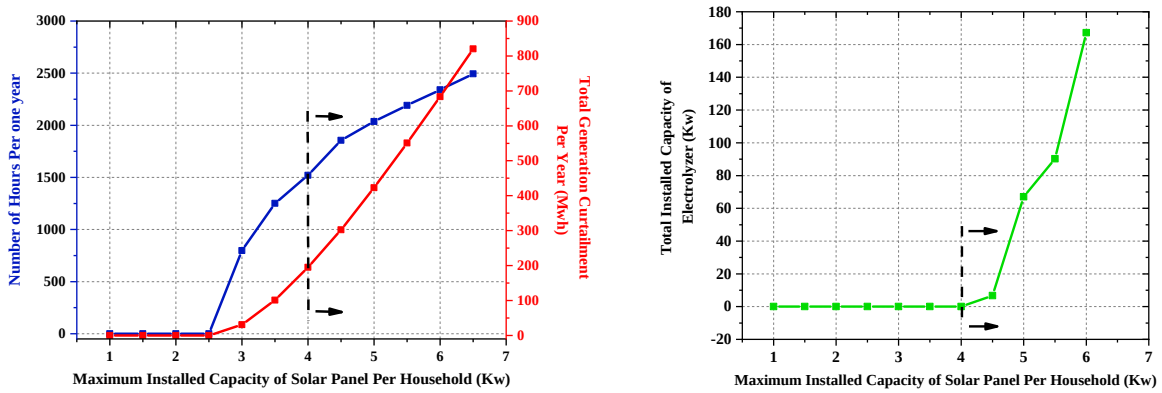
Looking at Fig. 7, it is apparent that once the electricity market price is more than the marginal price of the electrolyzer, the operation of the electrlyzer cannot be economical. So, its output power is zero. In addition, Fig. 7 declares that without proposing congestion prices as incentive-based signals for the electrolyzer, its deployment cannot be feasible. However, during the times when the network experiences congestion as a result of generation surplus, the amounts of congestion prices are negative. Therefore, in those times, the electric price for the electrolyzer, which is computed by summing congestion price and electricity market price, is less than the marginal revenue of the electrolyzer. Consequently, it is reasonable for the electrolyzer to operate and to absorb power at its maximum capacity from the grid. Similar justification is also true for the operation of fuel cells in the grid.

Table 2 demonstrates the optimal capacity and location for the installation of a combined electrolyzer-storage-fuel cell unit. (Option 2)

Table 2: Optimal siting and sizing of compressed unit

Node No.	Annual Cost Euro	Annual Profit Euro	Net Revenue Euro	Optimal Capacity (ELC)	Optimal Capacity (FC)	Optimal Capacity (HS)
10	29	126	97	60 (W)	500 (W)	10 (g)
12	2041	17293	15252	10 (kW)	26 (kW)	2 (Kg)

As mentioned, in the compressed option, the generated hydrogen from the electrolyzer at the particular operation time can only be used as fuel for the fuel cell to generate electric power at other times. According to the results in Table 2, we see that the optimal places for the installation of such combined



(a) (b)

Figure 8: Amount of generation curtailment and installed capacity of electrolyzers per different solar panel capacity

units are nodes 10 and 12. The reason for this selection relates to the amount of load shedding in the aforementioned nodes. Indeed, the congestion prices in those nodes are extremely high due to load shedding, hence, it is cost-effective for the owners of the fuel cell to generate power at those nodes to prevent load shedding. In this variant, it is not feasible to obtain benefits from selling hydrogen to the hydrogen market. The benefit is obtained only by injecting electric power into the grid once the system suffers from an overloading problem.

Deployment of electrolyzers in LV grids depends on the received congestion prices. In fact, applying such technologies in LV grids is practical in case of congestion in the grid. Fig. 8 which includes two sub-figures demonstrates that under which conditions of the grid, the installation of the electrolyzers can be an optimal option.

As seen in Fig. 8, the sensitivity analysis has been done in both sub-figures to show when application of the electrolyzers in LV grid can be useful. Fig. 8a demonstrates total generation curtailment and number of hours in which the grid experiences the generation curtailment for one year per different installed capacity of solar panels at each household. As expected, the power production of solar panels is a dominant factor in creating congestion in LV grids nowadays. Fig. 8a proves this fact as well. A growth in the amount of power production from solar panels can increase the amount of generation curtailment and the number of hours in which the grid deals with this problem. On the other hand, Fig. 8b depicts that once the maximum installed capacity of solar panels at each household of the case study exceeds 4Kw, expansion of the electrolyzers can be an optimal option from an economic perspective. Considering both Figs. 8a and 8b, it can be concluded that applying electrolyzers in LV grids is prac-

tical under condition that the grid experiences high generation curtailment. (Or the installed capacity of renewable resources is high enough). For the proposed case study, this amount must be more than 200 MWh. In addition, the number of hours that the grid sustains the generation curtailment should be more than 1500.

For a given capacity and location of electrolyzers in option 1, a break-even point has been calculated according to different installed capacity of PV systems at each home. Fig. 9 shows that point.

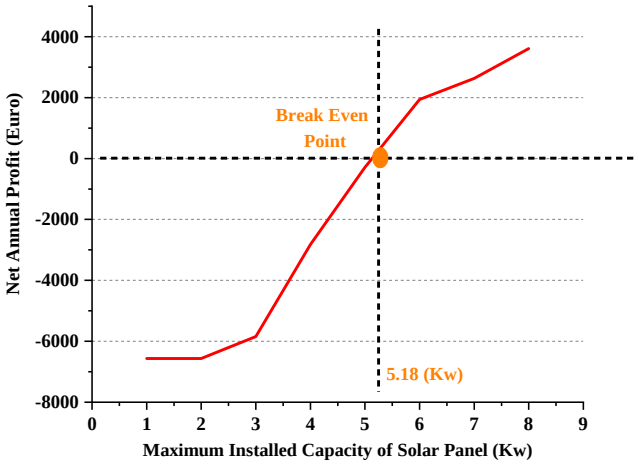


Figure 9: A break-even point for a given electrolyzers in option 1

As seen in Fig. 9, for a given deployment of electrolyzers in the grid, if the installed capacity of solar panels at each home becomes less than 5.18 Kw, the annual profit for them is negative. Again, this figure emphasizes that from economic point of view, installing these units is feasible for the grid with high integration level of renewable resources. In other words, deployment of P2G conversion systems can be justified in case of a high surplus generation in the LV grid. Two important uncertain factors in LV grids are the average power use of the customer and the output power of solar panels. Different configuration of these two uncertain parameters can change the break-even point for the electrolyzer as shown by Fig. 10

As shown in Fig. 10, once the installed capacity of solar panels at each home exceeds the amount of 5.5 KW, for any average power use, the application of the electrolyzers is economical. However, when the installed capacity of the solar panels is 5 Kw, the average power use of each home has to be less than 0.47 Kw for electrolyzers being profitable. To sum up, from Fig. 9 and 10, it is noteworthy to mention that the amount of surplus generation must be high enough for electrolyzers being profitable in LV networks.

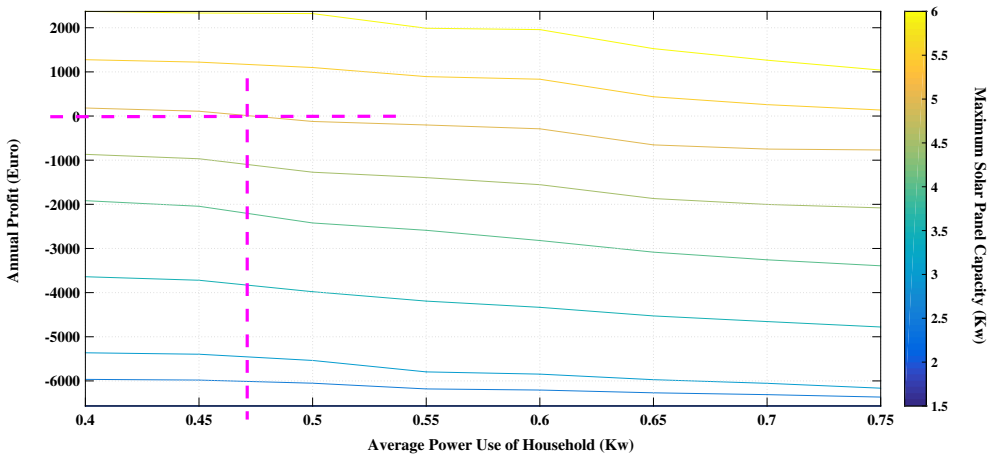


Figure 10: Annual profit of electrolyzers versus different configuration of household's average power use and installed PV panels

4.2.2. Flexibility improvement

In this part, it is verified how the optimal operation of P2G conversion systems can have positive effects on the grid. As explained in the previous section, P2G conversion systems respond to the received congestion prices and operate in a way that reduces the network cost. In this part, the effectiveness of the two defined options for deployment of the P2G conversion systems along with the employment of batteries in reducing congestion is examined.

It is noteworthy to mention that optimal sizing and siting for expansion of battery in the grid were specified based on the same method for the employment of the P2G conversion systems. Likewise to options 1 and 2, it is assumed that market participants decide to invest in the expansion of batteries in the grid to obtain profit from the optimal operation according to the received congestion prices. The optimal settings for batteries have been presented in Table. 3.

Table 3: Optimal siting and sizing of battery per node (capacity, usage and financial returns)

Node No.	Annual Cost Euro	Annual Profit Euro	Net Revenue Euro	Power (Kw)	Energy (Kwh)
11	2088	8006	5918	41.5	333
12	3790	9155	5365	72	562
24	2112	4922	2810	43	334

As seen, the net revenue during one year for the owner of batteries is positive. Indeed, it is cost-effective for the owner to buy electric power from the grid when the system suffers from surplus generation power. Because that amount of congestion price is negative and the net electricity price is less than the market price. In addition, the stored energy can be injected into the grid once load

shedding occurs and the amount of congestion price is high enough to encourage the owner of batteries to sell electric power to the grid.

Fig. 11 compares the effectiveness of options in reducing the generation curtailment in the grid.

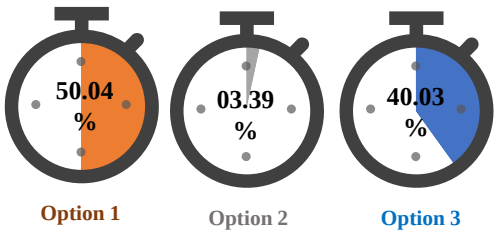


Figure 11: The contribution of each option in the reduction of the network's generation curtailment (in %)

As can be seen from Fig. 11, Option 1, the separated option, is more effective than others in reducing generation curtailments, which can reduce generation curtailments by 50%. In Option 1, the electrolyzer operates separately and the produced hydrogen can be sold to the hydrogen market without limit. Therefore, the electrolyzers can consume electricity at its full capacity when its marginal cost, the sum of electricity market price and congestion price, is less than its marginal revenue. However, Options 2, the compressed option, and Option 3, the battery storage, may not operate at its full capacity because they are only able to trade energy with the electric grid. Since the amount of load shedding in the grid (1.735 Mwh) is much lower than that of generation curtailment (686.06 Mwh), it is not economical for Option 2 to buy more power from the grid during surplus generation times because it can not sell too much electricity to the grid during the times when the grid faces overloading conditions. Hence, in this option, P2G cannot reduce generation curtailments too much. For a similar reason, battery usage has a moderate effect on reducing generation curtailments.

Network cost comprises of three terms: the cost of active power loss, the cost of load shedding, and the cost of generation curtailment. Fig. 12 demonstrates the effect of each option on the total network cost improvement.

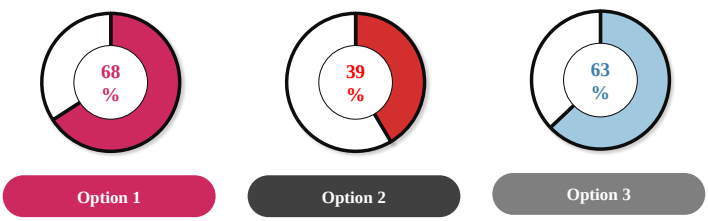


Figure 12: Network cost improvement per different options (in %)

As concluded from Fig. 12, the role of Option 1 in reducing the total network cost is a bit better than Option 3. Moreover, the deployment of batteries in the grid is preferable to Option 2 for reducing the network costs. Such findings can be explained by the fact that Option 1 and 3 have a significant positive effect on reduction of generation curtailment in the grid. In our model, social welfare has been defined by subtracting all costs (network costs + costs of installation and operation of different equipment) from the total benefit. Fig. 13 presents the percentage of improvement in social welfare for the three options separately.

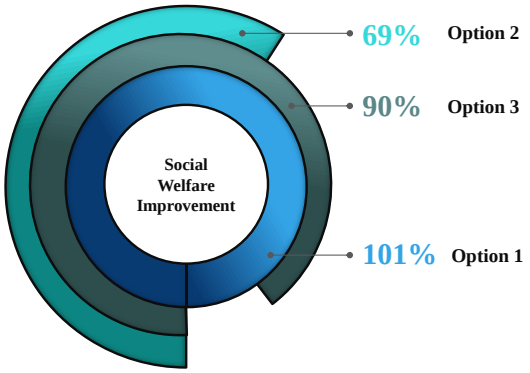


Figure 13: Social welfare improvement for 3 different options (in %)

From Fig. 13, it is seen that all options increase the social welfare in the grid. Option 1 increases the social welfare most because not only the gross revenue for all electrolyzers and fuel cells is high but also total network costs are less compared to other options.

5. Conclusion

This paper explored the economic feasibility of P2G conversion systems to solve the congestion problem in LV grids resulting from high injection levels of solar panels and strong growth in demand. We find that, the application of P2G conversion systems in LV grids can become a cost-effective opportunity once they receive congestion prices. Without considering such incentive-based prices, investment in P2G systems cannot be profitable. Furthermore, the optimal sizing and siting for expansion of P2G systems in LV grids are identified in this report. The results demonstrated that the selection of optimal settings for P2G conversion systems in LV grids not only can reduce grid congestion, but also can bring financial benefits for owners of P2G systems. In addition, a separate operation of electrolyzer and fuel cell is more efficient in reducing congestion resulting from high local generation in comparison to the compressed option and battery usage (Near to 50%). From our model analysis, we conclude that

employment of electrolyzers in LV grids for reducing congestion can be a practical alternative when the amount of surplus generation and the number of hours per year which the grid experiences the congestion become considerable. Moreover, our conclusions only hold when P2G conversion systems become available on the scale of households and their investment cost should have a linear proportion with the investment cost of large-scale P2G technologies. Finally, future work should concentrate on medium-voltage distribution grids where significant industrial companies use hydrogen as a feedstock. One of the research questions to be analyzed is to what extent the application of P2G systems can also contribute to solving the congestion problem in medium voltage distribution grids while meanwhile decarbonizing the industrial sector.

Acknowledgments

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Appendix A (Solution Method)

The proposed mathematical model for determining the optimal settings for the P2G conversion systems is a large-scale optimization problem. Solving this type of optimization problems in a centralized manner is challenging due to computational issues and intractability. Therefore, a decomposition approach is required for dealing with such problems. Benders decomposition as one of the popular approaches has been utilized in this paper to decompose the centralized mathematical model. In the remaining of this Appendix, it is shown how this decomposition method can be applied to the proposed model. As mentioned in subsection 3.1.2, the model has been comprised of two levels. Firstly, the bi-level problem must be converted into the single-level problem and then the recommended decomposition approach is used for solving the problem. Since the objective function and all constraints of the lower level problem is linear, this problem is convex. Hence, Karush-Kuhn-Tucker (KKT) conditions of this problem are sufficient for ensuring the optimality of the problem.

The general vector form of the optimization problem in the lower level can be written as follows:

$$Problem_{Main}^{LL}\begin{cases} \min_{\mathbf{X}} \quad f(\mathbf{X}) \\ \text{Subject to} \\ \text{Equality Constraints:} \quad \mathbf{H}(\mathbf{X}) = \mathbf{0} \quad : \lambda \\ \text{Inequality Constraints:} \quad \mathbf{G}(\mathbf{X}) \leq \mathbf{0} \quad : \mu \end{cases} \tag{A.1}$$

In above equation, $\mathbf{X}$ refers to vector form of all variables of the optimization problem. In addition, the objective function has been shown in general with $f(\mathbf{X})$. $\mathbf{H}(\mathbf{X})$, and $\mathbf{G}(\mathbf{X})$ depict vector forms of all equality and inequality constraints of the problem. According to the equation (A.1) and the Lagrangian function of $(\mathcal{L})$ which defined as $\mathcal{L}(\mathbf{X}, \lambda, \mu) = f(\mathbf{X}) + \lambda^T \mathbf{H}(\mathbf{X}) + \mu \mathbf{G}(\mathbf{X})$, the KKT of the lower level problem are formulated in a compact form as follows:

$$KKT_{Main}^{LL}\begin{cases} \nabla_x \mathcal{L}(\mathbf{X}, \lambda, \mu) = 0 \\ \nabla_\lambda \mathcal{L}(\mathbf{X}, \lambda, \mu) = 0 \\ \nabla_\mu \mathcal{L}(\mathbf{X}, \lambda, \mu) \leq 0 \\ \mu^T \nabla_\mu \mathcal{L}(\mathbf{X}, \lambda, \mu) = 0 \\ \mu \geq 0 \end{cases} \tag{A.2}$$

The optimization problem and all constraints shown in equation (A.1) are replaced with their equivalent KKT conditions in equation (A.2) and the proposed bi-level mathematical model is converted into the single level problem which is named Mathematical Program with Equilibrium Constraints (MPEC). Consequently, the general vector form of the new model can be organized as follows:

$$Problem_{Main}^{new}\begin{cases} \min_{\Theta,\Omega} \quad A_1^T\Theta + A_2^T\Omega \\ \text{Subject to} \\ A_3\Theta \leq A_4 \\ A_5\Omega + A_6\Theta \leq A_7 \\ \nabla_x \mathcal{L}(\mathbf{X}, \lambda, \mu) = 0 \\ \nabla_\lambda \mathcal{L}(\mathbf{X}, \lambda, \mu) = 0 \\ \nabla_\mu \mathcal{L}(\mathbf{X}, \lambda, \mu) \leq 0 \\ \mu^T \nabla_\mu \mathcal{L}(\mathbf{X}, \lambda, \mu) = 0 \\ \mu \geq 0 \end{cases} \tag{A.3}$$

In the new model, variables associated with the capacity of P2G conversion systems are complicating variables. Fixing of them to given values results in one decomposed optimization problem per operating condition. $(A_1^T\Theta)$ demonstrates vector form of capital costs for investing in P2G devices and $(A_2^T\Omega)$ refers to vector form of all operation costs and benefits obtained from operating them. $(A_3\Theta \leq A_4)$ shows investment constraints of the original problem and $(A_5\Omega + A_6\Theta \leq A_7)$ demonstrates all operational constraints of the problem.

According the Benders decomposition method, the new model in (A.3) can be divided into one master problem and sub-problems. For a particular operating condition, the sub-problem is formulated as follows:

$$Problem_{Main}^{Sub}\begin{cases} \min_{\Omega} \quad Z_{sub} = A_2^T\Omega \\ \text{Subject to} \\ A_5\Omega \le A_7 - A_6\Theta^{\star}, : \phi \\ \nabla_x \mathcal{L}(\mathbf{X}, \lambda, \mu) = 0 \\ \nabla_\lambda \mathcal{L}(\mathbf{X}, \lambda, \mu) = 0 \\ \nabla_\mu \mathcal{L}(\mathbf{X}, \lambda, \mu) \le 0 \\ \mu^T \nabla_\mu \mathcal{L}(\mathbf{X}, \lambda, \mu) = 0 \\ \mu \ge 0 \end{cases} \tag{A.4}$$

In the above problem, $\mu^T \nabla_\mu \mathcal{L}(\mathbf{X}, \lambda, \mu) = 0$ can be expressed as $\mu_j g_j(\mathbf{X}) = 0$ for jth inequality constraint of the lower level problem. As seen, this constrain is nonlinear. This type of constraint can be linearized based on a new auxiliary binary (I_j) and big enough constants (M^1, M^2) as follows:

$$g_j(\mathbf{X}) \le I_j M^1 \tag{A.5}$$

$$\mu_j \le (1 - I_j) M^2 \tag{A.6}$$

In addition, there are nonlinear expressions in the objective function of the sub-problem which stems from the product of the congestion price and the amount of power bought/sell from/to the grid by electrolyzer/fuel cell. Such expressions are replaced by linear terms based on the strong duality theorem (STD). Consequently, the sub-problem becomes linear and can be solved by practical solvers. The problem in (A.4) is solved based on given values for the capacities of the P2G conversion systems ($\Theta^{\star}$). After solving the sub-problems, the sensitivities of the P2G owner's operation profit are computed with respect to the capacity decisions. In fact, they can be obtained through dual variables associated with constraints fixing the capacity decisions (ϕ). In addition, the upper bound of the problem is updated as follows:

$$UB = A_1^T\Theta^{\star} + Z_{sub}^{\star} \tag{A.7}$$

According to the new amount of sensitivity, a new optimality cut ($\Gamma \ge Z_{sub,r-1}^{\star} + \phi^{\star r-1}\left[\Theta - \Theta_{\mathbf{r-1}}^{\star}\right]$) is added to the master problem. Then, according to new optimality cut, new settings for the optimal capacity of the P2G conversion systems are specified in the master problem. The updated master

problem for the rth iteration, can be formulated in vector form as follows:

$$MP^{update}\begin{cases} \min_{\Theta} \quad A_1^T\Theta + \Gamma \\ \text{Subject to:} \\ A_3\Theta \leq A_4 \\ \Gamma \geq Z^{\star}_{sub,r-1} + \phi^{\star}_{r-1}\Big[\Theta - \Theta^{\star}_{\mathbf{r-1}}\Big], \quad \forall r \in m \end{cases} \tag{A.8}$$

After solving this problem, the lower bound of this technique is updated as follows:

$$LB = A_1^T\Theta^{\star} + \Gamma^{\star} \tag{A.9}$$

Finally, the proposed iterative approach stops when the difference between the amount of upper bound and lower bound is less than epsilon. ($UB - LB \leq \epsilon$)

Appendix B (Case Study Description)

To assess the effectiveness of P2G conversion systems in providing flexibility to LV grids, the proposed mathematical model for expansion of such technologies has been verified on a typical LV grid of the Dutch power system [44]. This subsection introduces the characteristics of the case study and the assumptions in the simulation.

Characteristics of the case study

The considered case study comprises of 24 nodes and 23 lines which connect to the upstream network through a 250 KVA transformer. Fig. 14 shows this case study in a schematic way.

The characteristics of each type of cable can be found in Table. 4.

Table 4: Characteristics of cables used in the case study

Cable Type	Current carrying (Amp)	Resistance (Ω/Km)	Reactance (Ω/Km)
A	265	0.206	0.079
B	204	0.320	0.082
C	138	0.641	0.085
D	81	1.910	0.532
E	80	1.837	0.088
F	60	3.061	0.100

In this simulation, it is assumed that each household is equipped with a rooftop solar system with a capacity of 6 Kw. The average residential power use of each household during one year is assumed to

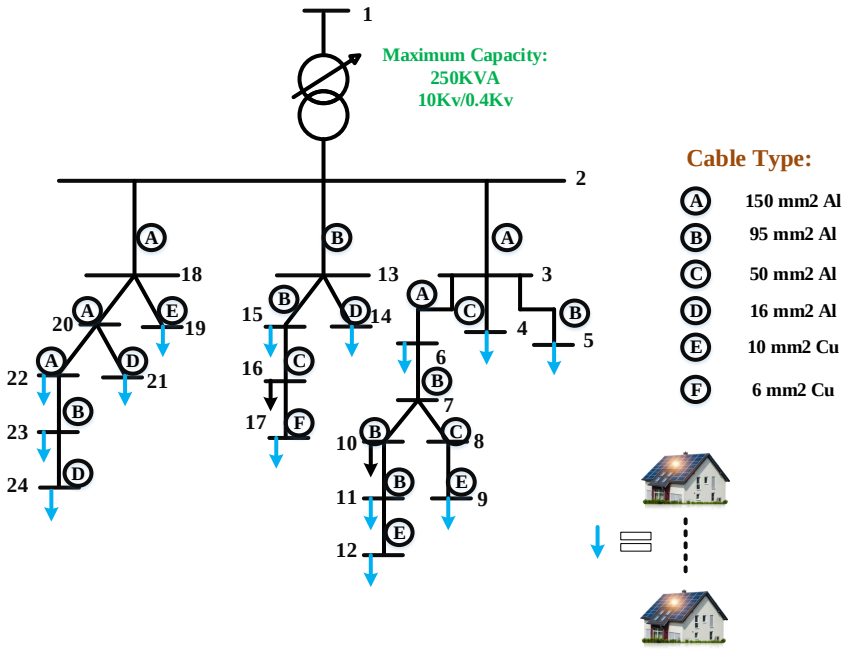

Figure 14: Typical LV Grid in the Netherlands

be 0.6 Kw. In this case study, the total number of households is 160 and the number of households at each node varies (See Fig. 15).

Characteristics of load and generation:

Profile factors of load, electricity market price, and hydrogen market price for one year have been assumed as Fig. 16 in this simulation.

In this paper, all simulations have been done for the city of Groningen with Latitude of 53.216 Deg and a longitude of 6.566 Deg[1]. As expected, the output power of solar panels depends on the irradiance of the sun. According to the irradiance of the sun and the maximum capacity of solar panel, the actual amount of power generation can be found by equation (B.1) as follows:

$$Q^{E}_{RN_{t,n}} = \begin{cases} Q^{Cap}_{PV} & G_a(t) \geq G_{STD.} \\ Q^{Cap}_{PV} \times \frac{G_a}{G_{STD.}} & G_{Crt.} \leq G_a(t) \leq G_{STD.} \\ Q^{Cap}_{PV} \times \frac{G_a^2}{G_{STD.}G_{Crt.}} & 0 \leq G_a(t) \leq G_{Crt.} \end{cases} \tag{B.1}$$

$G_{STD.}$ and $G_{Crt.}$ stand for the standard solar irradiance [1000 (W/m^2)] and certain irradiance point [150 (W/m^2)] respectively. As seen, once the irradiance of sun at the particular region is more than

[1]The hourly irradiance of the sun for the city of Groningen has been extracted from "www. re.jrc.ec.europa.eu"

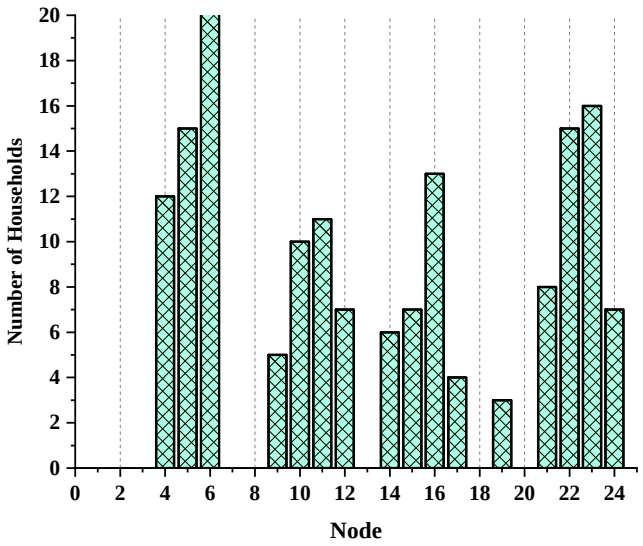

Figure 15: Number of households connected to each busbar

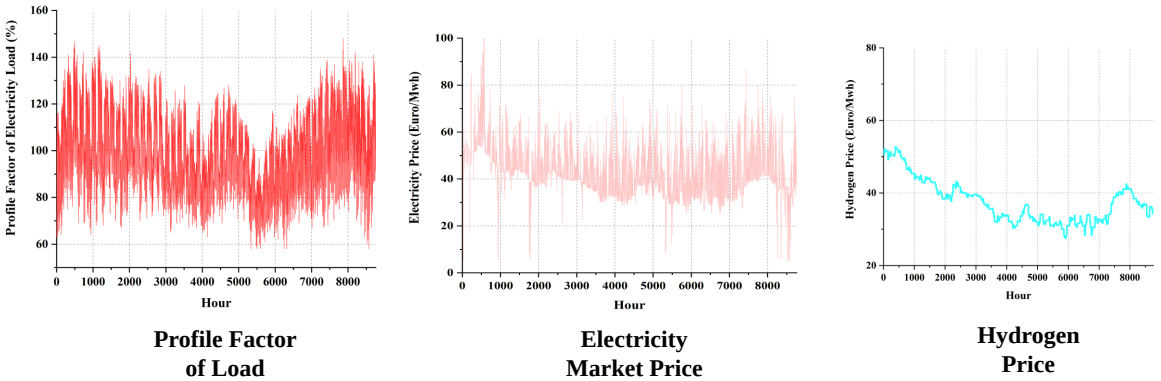

Figure 16: Profile Factor of Load, Electricity Market Price, Hydrogen Market Price

the standard amount, the solar panel can produce at its capacity. Otherwise, the production power is less than its capacity.

In this simulation, the price for compensating generation curtailment has been assumed to be 50 Euro/Mwh, while the load shedding price is assumed to be the same as value of loss load (10000 Euro/Mwh). Furthermore, the electricity market price at each hour is considered as a price for buying power due to active loss in the grid. As explained in previous subsections, two options have been considered for expansion of P2G conversion systems in LV grids i.e., the separate option and the compressed option. Furthermore, in this paper, it is verified how investing in electric batteries can bring financial gains for owners of them along with increasing social welfare in the grid. The initial parameters for P2G conversion technologies utilized in the separated and compressed options along with the initial data for batteries can be found in Table. 5.

Table 5: Initial Parameters for the optimization Problem

Item	Amount	Unit
CAPEX for Electrolyzer	1×10^6	Euro/Mw
CAPEX for Fuel cell	1×10^6	Euro/Mw
CAPEX for Storage Tank	1.76×10^3	\$/Kg-H_2
Discount Rate	2.5	%
Lifetime of Electrolyzer and Fuel cell	25	Year
Efficiency of Electrolyzer	75	%
Efficiency of Fuel cell	40	%
Power capital cost of Battery (Lead-Acid)	250	\$/Kw
Energy capital cost of Battery (Lead-Acid)	75	\$/Kw
Efficiency of Battery	80	%
Lifetime of Battery	13	Year
DOD of Battery	50	%

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