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Allocating Causality-based Network Service Charges in P2P Electricity Trading for Cost-Efficient Power System Operation: System Loss and Violation Charges

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Abstract

Allocating Causality-based Network Service Charges in P2P Electricity Trading for Cost-Efficient Power System Operation: System Loss and Violation Charges

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Integration of distributed energy resources has led to the attraction of the Peer-to-Peer (P2P) electricity market as a new way of operating the distribution network. P2P electricity market mechanisms can be classified into centralized and decentralized mechanism, with the latter receiving significant attention due to accommodating multiple market participants with different trading objectives in the market. However, in a decentralized P2P electricity market where transactions are conducted solely for the benefit of market participants. Consequently, transaction may result in excessive system losses and network violations. To address these issues, this dissertation proposes a network operation scheme of distribution system operator (DSO) who is responsible for ensuring stable and efficient network

operation. The proposed approach aims to reduce system losses and enhance the total welfare of P2P electricity trading while maintaining the reliability of the distribution network by imposing network service charges, such as the system loss cost and network violation cost, as price signals during transactions.

Allocation of the system loss proposed in this dissertation is designed based on the cost-causality principle. It is demonstrated that the system loss charge can result in the optimal market outcome in the P2P electricity market where, the participants carry out electricity transaction in non-cooperative way. This is proven using a method that shows the equivalence between the Nash equilibrium condition and the stationary condition satisfying the optimal market outcome. It is also observed that equal distribution of system loss cost fails to satisfy the optimal market condition. Furthermore, this research proposes methods for setting the system loss charge based on the cost-causality principle, using incremental transmission loss coefficient and Shapely value.

A P2P trading mechanism for allocating the system loss charge is proposed in this dissertation. The utility function of market participants is defined including the system loss price, and the market model is formulated as an optimization problem. To solve this problem using a decentralized manner such as, the exchange of trading information among market participants, the gradient method and dual decomposition technique are used to establish a trading procedure. The DSO notifies market participants of the allocated system loss charge during the process. Market participants update their cost or utility function, determine optimal trading strategies and exchange the trading information with their trading counterparties to obtain converged trading results.

The trading process, which allocate the network violation costs, is also based on an iterative exchange of transaction information to derive converged market results. The sensitivity factors used in this process provides high accuracy in estimating the network state and violations, and can replace the nonlinear power flow equations to ensure market scalability. During the exchange of trading information, the DSO sets network violation charge estimated by the exchanged trading information and distributes them using the sensitivity factors. In other words, the participants, who is expected to cause network violations is informed of the network violation charge corresponding to the level of the violation they contributed, thereby inducing the participants to trade within the range where network violations do not occur.

The proposed scheme for the P2P electricity trading, which manages efficient network operation, is validated using the modified IEEE 33 test system. The simulation results show that the proposed network operation by allocating network charge led to a decrease in system losses, improving network efficiency compared to a market where system loss charges are distributed equally. The cost causality-based network violation charge can increase the total trading volume and the social welfare while reducing congestion and improving voltage security when comparing the network violation charge is fixed. Furthermore, when compared to congestion management using power transfer distribution factor (PTDF), the sensitivity factors used for the network operation exhibits a high level of accuracy in calculating line flow, while maintaining computational efficiency.

This dissertation presents the cost-efficient power system operation scheme for the DSO to coordinate with a decentralized P2P electricity trading in the distribution network. The proposed scheme aims to ensure the sustainability of the P2P electricity market while maintaining efficient and reliable network operation. Moreover, the

results of research can provide new guidelines for the distribution network utilization costs in response to the changing distribution network environment from the traditional vertical and unidirectional to an active and bi-directional energy flows.

Keywords: Cost-causality principle, cost-efficient system operation, distribution network operator, system loss charge, network violation charge, P2P electricity trading
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Nomenclature

A. Abbreviations

DSO	Distribution system operator
FIT	Feed in tariff
P2P	Peer-to-peer
PTDF	Power transfer distribution factor
RES	Renewable energy source

B. Sets and Indices

$n, m \in \mathcal{N}$	Set of nodes
$j \in N_C$	Set of consumers
$l \in \mathcal{L}$	Set of lines
$i \in N_p$	Set of prosumers
S	Slack node
k	Iteration step number

C. Parameters

$Y_{n,m}$	Admittance between node n and m [p.u.]
$C(\cdot)$	Cost function of prosumer [¢/kWh]
$a_i, \mathrm{b_i}, c_i$	Cost function parameters of prosumer [¢/kWh^2], [¢/kWh], [¢]
$fs_{l,n}$	Line flow sensitivity at line l according to active power change node n
$\underline{sf_l}, \overline{sf}_l$	Minimum and maximum line flow limits at line l [kVA]
$\overline{p}, \underline{p}$	Minimum and maximum power limits of prosumer and consumer [kW]
$\lvert\underline{v}_n\rvert, \lvert\overline{v}_n\rvert$	Minimum and maximum voltage limits at node n [p.u.]
X_l	Reactance of line l [p.u.]
R_l	Resistance of line l [p.u.]
c	Unit system loss charge to prosumer and consumer [¢/kWh]
$l_i(\cdot)$	System loss allocated to prosumer and consumer [kWh]

Λ	The unit system loss price for loss compensation [¢]
$U_j(\cdot)$	Utility function of consumer [¢/kWh]
$\alpha_j, \beta_\mathrm{j}, \gamma_j$	Utility function parameters of consumer [¢/kWh^2], [¢/kWh], [¢]
$WC(\cdot)$	Welfare of consumer [¢]
$WP(\cdot)$	Welfare of prosumer [¢]
$vs_{n,m}$	Voltage sensitivity at node n according to active power change node m

D. Variables

p_l, q_l	Active and reactive power flow of line l [kW], [kVAr]
pl_l, ql_l	Active and reactive power loss of line l [kW], [kVAr]
sf_l	Apparent flow at line l [kVA]
s_n	Apparent power at node n [kVA]
λ_i	Dual variable of the active power balance constraint for prosumer i [¢/kWh]
$\overline{\xi}_l, \underline{\xi_l}$	Dual variable of the maximum and minimum line flow constraint at line l [¢/kWh]
$\overline{\nu_j}, \underline{\nu_j}$	Dual variable of the maximum and minimum power demand constraint for consumer j [¢/kWh]
$\overline{\mu_i}, \underline{\mu_i}$	Dual variable of the maximum and minimum power output constraint for prosumer i [¢/kWh]
$\overline{\chi}_n, \underline{\chi}_n$	Dual variable of the maximum and minimum voltage constraint at node n [¢/kWh]
P_L	System losses [kWh]
$\phi_{m,n}$	Causal relationship factor for between system loss and active power at node n calculated by incremental transmission loss
$\phi_{s,n}$	Causal relationship factor for between system loss and active power at node n calculated by shapely value
$p_{j,i}$	Trading volume between consumer j and prosumer i [kWh]
p_i	Trading volume of prosumer i [kWh]
v_n	Voltage at node n [p.u.]
$v_{s,l}, v_{r,l}$	Voltage magnitude at the sending and receiving node [p.u.]
δ_n	Voltage phase angle at node n [rad]

Chapter 1 Introduction

1.1 Background and motivation

Over the past decades, the capacity of renewable energy source (RES) has increased rapidly following the global paradigm shift toward decarbonization and technological advances in power systems. The capacity of photovoltaic generators predominantly connected to distribution networks has increased from 40 GW in 2010 to 709 GW in 2020 with an average annual growth rate of 33%. With adequate planning, RES connected to the distribution network can provide multiple advantages to the power system such as decreasing system losses, avoiding excessive network investment, improving reliability, and reducing greenhouse gas emissions [1, 2]. Further, the owners of distributed RES or prosumers can pursue economic benefits by producing and selling electricity, and this can encourage prosumers to actively participate in load management in the power system [3].

Several countries support the expansion of RES through various regulatory policies. Among these, the feed-in tariff (FIT) is considered the most effective method for facilitating RES adoption [4]. The central principle of FIT is to offer guaranteed fixed prices for electricity produced from RESs during a specific period [5]. Further, net metering is effective because this method compensates for the net amount of generated electricity at the retail price [6]. However, FIT and net metering policies have one common disadvantage. In both policies, prosumers cannot freely and dynamically decide the price and amount of electricity in a transaction; therefore, they cannot maximize their utility [7]. Certain countries, where the renewable energy penetration goal has been achieved to a large extent and the investment cost for RES has fallen to a low level, have started to suspend regulatory support for RES generation [7]. In such circumstances, benefits obtained by prosumers can be reduced significantly, and their positive roles in the power system may be undermined [8].

In response to limitations in existing policies for RES and changes in the level of support, peer-to-peer (P2P) electricity trading is now attracting considerable research attention as an effective management scheme for prosumers with RES in the distribution network [8-10]. In P2P electricity trading, prosumers directly trade electricity with each other or with consumers, and during the trading process, they agree on an appropriate price, e.g., a price ranging between the time-of-use price and FIT. Thus, prosumers and consumers can achieve a win–win outcome consumers can save costs, while prosumers receive more profit.

Even though there can be various market architecture for the P2P electricity trading, the main market plyers of the P2P electricity market are commonly recognized as prosumers, consumers and Distribution system operator (DSO) as shown in Figure 1 [10-12]. Prosumers are agents who produce electricity using their own distributed generation resources; they pursue economic profit by selling excess electricity to consumers in the distribution network. Prosumers also have the option of selling electricity to a supplier in the distribution network at a predefined contract price cheaper than the P2P trading price. Consumers purchase electricity via P2P trading. Further, they can buy electricity from a supplier at the retail price when the electricity procured from P2P trading is insufficient; this is more expensive than the trading price. The DSO conducts operation and planning tasks for the distribution network, where prosumers and consumers are physically interconnected and interact commercially. The DSO has the right to restrict P2P transactions causing network malfunctions, and they are verified based on the trading information from the platform for P2P electricity trading. A trading platform is a technical system that implements P2P market functions such as matching, clearing, and settlement without the intervention of any intermediary agent. Further, The DSO is responsible for balancing supply and demand, which compensates for system losses and provisions ancillary services by considering transactions in both the P2P electricity and conventional electricity markets.

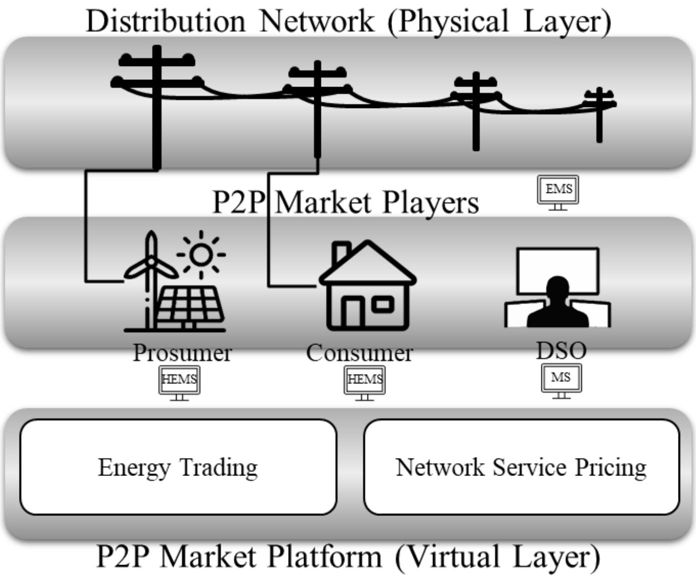

Figure 1 Market architecture of P2P electricity trading in distribution networks

Although there can be various market mechanism of the P2P electricity market, it can be categorized into centralized and decentralized market mechanisms. The centralized mechanism collects bids from market participants and determines the electricity price and trading volume based on the objective of the market such as maximizing social welfare or minimizing production costs as shown in Figure 2. This is like the traditional wholesale electricity market and called system-centric P2P electricity trading [13]. The market results are calculated to maximize the welfare of the market participants. Consequently, the market efficiency than the decentralized mechanism when trading parties directly determine the transaction parameters. However, market efficiency deteriorates when a player abuses the market power to manipulate the merit order of resources [14]. Further, Electricity trading differs from other commodities as it must account for the system losses and constraint violations within the network. Under the centralized electricity market, centralized coordination by the system operator is used to determine the optimal market outcome, considering the system losses and constraints violations.

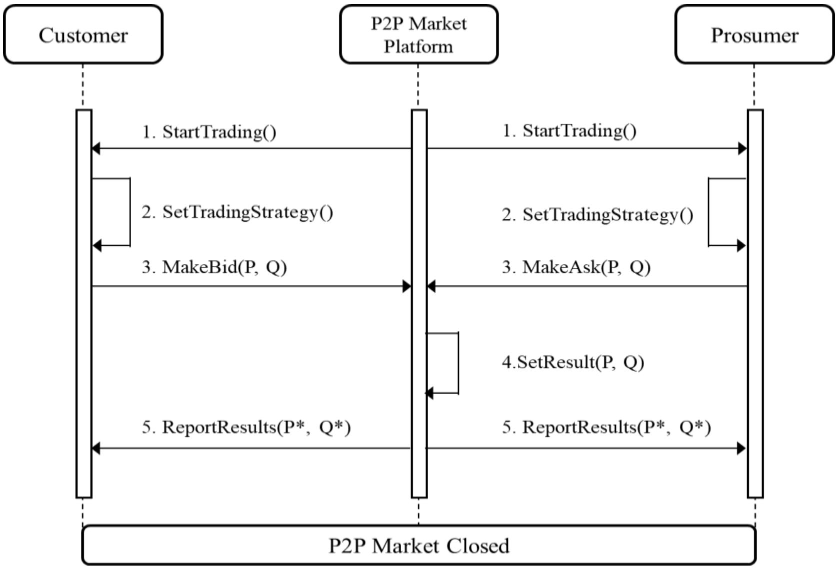

Figure 2 Sequence diagram illustrating synchronous pricing for P2P electricity trading. (P, Q: bidding price and volume, respectively; P*, Q*: determined price and volume, respectively)

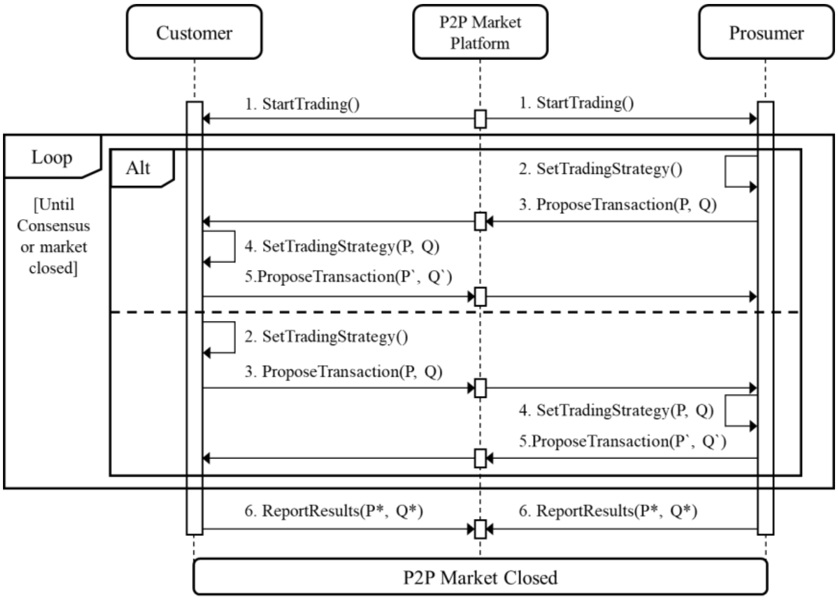

Figure 3 Sequence diagram illustrating P2P electricity trading process in the decentralized market (P, Q: proposed price and volume, respectively; P`, Q`: adjusted price and volume according to trading strategy, respectively; and P*, Q*: determined price and volume, respectively)

The approach is a decentralized mechanism that allows prosumers and consumers to directly communicate with each other and conduct electricity trading without the need for any centralized coordination. This approach has several advantages. Firstly, it eliminates the economic and political influence from centralized markets, providing a more autonomous and independent trading environment [15]. Secondly, it allows market participants to engage in electricity trading based on factors such as prices and their own heterogeneous preferences, including considerations such as reputation and green energy sources [16]. This provides greater flexibility and customization in electricity trading decisions. Lastly, this decentralized mechanism is expected to exhibit exceptional scalability, as it can accommodate diverse objectives of prosumers, who may have different goals and priorities in their energy trading activities [17]. Figure 3 illustrates the trading process and the dynamic interaction between prosumers and consumers in this decentralized P2P electricity market.

However, market outcomes may have unforeseen effects on the network. This is because market participants trade solely for their own benefit, without considering the efficient and safe operation of the grid. Their trading practices not only reduce the efficiency of grid operations but also result in trading outcomes that violate the network constraints [18]. The increased cost of grid losses not only reduces social utility but also affects the utility of market participants who have to compensate for these losses, potentially decreasing their incentive to participate in the inter-personal power trading market. Furthermore, violations of the network constraints of the grid due to trading can lead to grid failures and accidents, compromising the stability and reliability of the power grid. This can result in power supply interruptions, degradation of power quality, disruption of customer service, and economic losses.

Despite the issues encountered in decentralized P2P trading markets, finding a solution is not straightforward. Cooperation in network operation among market participants is a challenging. they engage in transactions for their own purposes, lacking awareness of the impact on the network. Moreover, they are not the unit dispatched for efficient and reliable network operation. This poses a challenge for the DSO to promote cooperation for network operation, potentially resulting in transaction outcomes conflicting with their interests [19]. Given this context, this dissertation proposes an approach of the DSO that can encourage cooperation among market participants, aiming for cost-effectively network operation scheme to reduce system losses and ensure the reliability of distribution network.

1.2 Previous researches and limitation

Table 1 presents a summary of previous studies on allocation of system losses, the ex-post method has been employed to manage system losses resulting from P2P electricity markets. This means that system losses and the costs to be paid by market participants are calculated based on the state of the network after the bidding is finished. However, it is challenging to determine the network loss price to compensate for system losses, because they exhibit nonlinearity with respect to line flows, and the nonlinear nature of electrical laws prevents the precise determination of the portion of line power flow that can be attributed to a specific trading volume. Therefore, researchers have considered how to distribute system loss costs fairly and effectively in many traditional markets.

Incremental transmission loss coefficient is used in [11, 20-22]. it is the change in total losses due to an incremental change in power injected in a bus. Therefore, to distribute the loss cost, a linear approximation of the injected power of each bus is used, which reduces the total loss. However, due to the nonlinear nature of the loss, post-processing such as normalization is required. This is because the actual loss and the value obtained by the coefficient do not match, and a negative price may occur, causing cross-subsidization problems.

The power-tracing method can calculate the contribution of the transacted power to the line loss based on a proportional assumption based on Kirchhoff's current law [23, 24]. The amount of outflow contributed by a source is defined based on the ratio of inflow from the source to the total inflow to a node; this method can be used in both synchronous and asynchronous pricing because the contribution of each line of a trading volume can be determined regardless of the trading party. However, this method may be difficult to use because it is necessary to calculate the inversion of the sparse matrix.

However, all of these methods are executed ex-post facto, meaning that all transactions are determined after the fact and based on precise system state information, allowing for an accurate and fair allocation of the system loss charge. Because these methods do not offer market participants precise system loss chare in advance, they may not only lead to non-cooperation among market participants but also transfer the settlement risk of system loss to market participants, potentially reducing the incentive to participate in the P2P market. Therefore, ex-ante allocation on system losses charge is necessary to encourage market participants to cooperate for reducing system losses.

On the other hand, there are studies to inform market participants of the exact charge for system losses to be paid before a trade occurs. This not only ensures the utility of market participants to pay for system losses, but also acts as a price signal to induce market participants to cooperate for loss management. In [25-30], Postage-stamp is used to equally distribute system loss. The cost is allocated to market participants in proportion to the trading volume, regardless of the network. It is a simple and easy-to-understand method that can provide transparency, however, the limitation of this scheme arises from the fact that the trading volume is not linearly related to the power flow in a network; thus, a small loss cost is charged to a prosumer with a small trading volume, even if the trade incurs considerable network operating costs. Thus, cost causality-based system loss charge, which compensate the cost in proportion to the level of the incurred system losses, should be implemented to induce market percipients to cooperate for reducing system losses.

Table 1 Comparison of Previous research on system loss management methods.

Methodology	Allocation time	Coordination for system operation		Conflict of interest		Ref
		Advanced information	Cost-causality	DSO	Prosumer Consumer	
Incremental Transmission Loss	Ex-post	X	O	X	O	[11, 20-22]
Proportional Sharing		X	O			[23, 24]
Postage-Stamp	Ex-ante	O	X	O	X	[25-30]
Causality-based methods		O	O	X	X	This dissertation

Numerous previous studies have also proposed ways to manage the network violations to ensure reliable network operation as shown in Table 2. This approach can be classified into two categories: constraint-based management and cost-based management. Constraint-based management is a method that restricts transactions that would cause network violations. On the other hand, cost-based management involves setting violation charges and allocating them to market participants, thereby incentivizing them to engage in transactions that do not cause violations.

The DSO ensures the reliability of the network by specifying the same trading limit for all market participants when they perform transactions in countries such as Australia, where P2P electricity trading is practiced. This method has the advantage of being very easy to apply in practice, however, it does not allow for P2P electricity trading that can create more utility, resulting in transaction results that reduce the efficiency of the market as it does not reflect the network status according to the transaction [31-33].

The method presented in [34] proposes P2P electricity trading based on a market transaction with a continuous double auction. In this market, when a transaction is established between a prosumer and a consumer, the DSO checks network violations using power transfer distribution factor (PTDF) and voltage sensitivity. If the DSO finds that the established transaction causes a network violation, the DSO cancels the transaction. This method has the advantage of stabilizing network operation by blocking transactions that cause network violations. However, there is a possibility that the transaction that causes the violation may not be detected because sensitivity caused by DC-power flow is used in the distribution system, where the line resistance of the network cannot be ignored. Additionally, since it imposes unilateral restrictions on transactions that cause violations after the transaction has been established, it is not possible to deliver guidance to market participants to derive transaction results that are consistent with efficient and stable operation results.

The utility in [13] uses a two-level P2P electricity trading method. In the lower layer, market participants perform transactions through a decentralized mechanism, and the transaction results are delivered to the utility. The utility then considers the transaction results and performs optimal power flow to establish an optimal grid operation method. If a network violation is found according to the result of optimal power flow, the utility imposes the same penalty on all market participants. By repeating the process of performing adjusted transactions after confirming the penalty, market participants can derive the results of P2P electricity trading corresponding to reliable grid operation results. Although this approach has the advantage of accurately detecting network violations by solving AC power flow, scalability problems may occur due to the computational burden required to solve AC power flow, which increases as the number of market participants and the size of the network increases. In addition, imposing penalties on all market participants equally when a violation occurs can lead to a reduction in overall market utility by spreading the responsibility for network violations.

As a response to this problem, violation charge based on the amount of network violation caused can be considered. Methods have been proposed to estimate and distribute the line congestion caused by market participants using network sensitivity, as proposed in [35, 36]. However, many of these studies use DC-sensitivity, which is not suitable for distribution systems with high line resistance, unlike transmission systems. This can result in inaccurate estimation of network violations or inefficient penalties for network violations.

Finally, system losses and network violation management methods can be categorized into ex ante and ex post approaches. The ex post method reflects the results of P2P electricity trading to the network, enabling accurate cost distribution and reliable network operation. However, since it evaluates the trading results after the fact, it has limitations in inducing trading results that lead to optimal operation outcomes. On the other hand, ex ante methods are suitable for inducing transaction results that align with the objectives of DSOs. However, in order to effectively induce transaction results, a method that can accurately analyze the impact of transaction results on the network is required.

Table 2 Comparison of previous research on network constraints managements methods.

Constraints management schemes		Cost-causality	Calculation methods	Limitations		Ref.
				Economic efficiency	Functionality	
Constraint-based management	Upper limitation	X				[31-33]
	Ex-post curtailment	X	PTDF	Decrease in social welfare	Voltage violation, Calculation accuracy	[34]
Cost-based management	Fixed cost	X	Optimal power flow equation		Market scalability	[13]
	Cost allocation	O	PTDF		Voltage violation, Calculation accuracy	[35, 36]
		O	Sensitivity factors			This dissertation

1.3 Objectives of the dissertation

Electricity trading on networks must be operated considering the system losses and network violations. In addition, in order to increase the incentive for market participants to participate in the power market, market efficiency must be guaranteed, and for this purpose, it is necessary to manage system losses caused by transactions. However, it is necessary to induce the cooperation of market participants to derive efficient and reliable market results in a P2P electricity market with a decentralized market mechanism. Many previous studies have proposed methods for this, but it is still a challenging problem. Against this background, the objective of this dissertation is to suggest an operational scheme for DSOs that can ensure the efficiency and reliability of distribution networks with a P2P electricity market operated by a decentralized mechanism.

First, this dissertation estimates the total system losses caused by transactions and establishes an operational scheme to distribute costs according to the losses caused by individual transactions, confirming that the method of allocating system loss costs according to the cost-causality principle is more suitable for optimal market efficiency than other methods. It is proposed that a cost allocation method based on the cost-causality principle that can be applied to the P2P electricity trading. However, even if the cost allocation method based on the cost-causality principle is used, the DSO inevitably bear the settlement risk of system losses. Therefore, this study proposes an iterative decentralized market mechanism and verifies the effectiveness of the loss cost distribution method based on the cost-causality principle by utilizing the proposed market mechanism.

Finally, network operation scheme for the DSO that can induce the cooperation of market participants to prevent transactions causing network constraints is proposed. The operational scheme proposed in this research utilizes sensitivity factor to secure operational scalability in an environment where multiple market participants can access the network. The sensitivity factor is derived using partial derivative and chain rules through power flow equation to reflect the characteristics of the distribution network where the resistance value of the line is very high and the difference between magnitude of node voltage is not ignorable. It is shown that the proposed operational scheme, is more reliable than the one using PTDF in previous studies. In addition, it is shown that the violation charge can be distributed according to the cost-causality principle when using the sensitivity factor, and that the operational scheme leads to much better market efficiency than a management scheme for allocating fixed violation charge to all market participants.

In conclusion, this dissertation proposes a network operation schemes for the DSO to induce cooperation among participants in P2P electricity market using network charges. The DSO implements a cost-causality allocation of charges for system losses and violations resulting from P2P electricity trading, thereby maximizing social welfare in operational outcomes. Moreover, the sensitivity factor utilized in this study offers computational efficiency and accuracy in detecting violations, ensuring reliable distribution system operation.

1.4 Overview of the dissertation

The remainder of this dissertation is organized as follows. Chapter 2 of the dissertation focuses on comparing the efficiency of market outcomes when applying different methods of distributing system losses in a P2P electricity market. The market model assumes that the utility of market participants converges with the amount of electricity traded, and the contribution to system losses is differentiated based on the trading volume of market participants located at each node of the network. In this chapter, two market outcomes are compared: one operated by a centralized mechanism that leads to an optimal market outcome, and the other where all market participants participate competitively and reach a Nash equilibrium. By comparing the conditions that satisfy the optimal market outcome in the first market with the operating results that satisfy the market outcome at Nash equilibrium in the second market, it is confirmed that the market with loss cost allocation according to the cost-causality principle is more suitable for achieving the optimal market outcome. The chapter also presents the loss allocation method based on the cost-causality principle using incremental loss allocation and Shapley value.

Chapter 3 introduces the loss management scheme of DSO in a P2P electricity market with a decentralized market mechanism, which applies the loss allocation method based on the cost-causality principle presented in chapter 2. DSO estimates the system losses that occur in the network based on the exchanged transaction information among market participants and charges each market participant for the losses based on the cost-causality principle. This process is repeated until the results of the transactions converge. The chapter presents the market clearing algorithm using the Lagrangian decomposition technique to represent the P2P electricity trading based on the decentralized mechanism with the operational scheme for system loss management.

Chapter 4 focuses on the scheme to manage network violations by DSOs in a P2P electricity market with a decentralized market mechanism. The chapter proposes a sensitivity factor based on power flow equation to reflect the characteristics of distribution networks. DSO checks whether a network violation occurs due to the transaction results based on the repeatedly exchanged transaction information of market participants. If a violation occurs, the market participant is charged a penalty, which is distributed utilizing network sensitivity according to the size of the violation caused by each market participant. The chapter presents a market clearing algorithm that incorporates this scheme in the market clearing algorithm used in Chapter 3.

In Chapter 5, case studies are conducted to experimentally verify the network management schemes of DSOs introduced in chapters 3. A test bed with 16 consumers and 7 prosumers in the IEEE 33-bus test distribution network is designed to reflect the network environment where P2P electricity trading occurs. The first case study compares the market utility and system loss items under the equal allocation method, marginal allocation method, and loss allocation method using the Shapley value to check the effectiveness of the loss management scheme reflecting the cost-causality principle. In Chapter 6, case studies verify the function of the network violation management scheme utilizing sensitivity factor. The results of the case studies show that the network management scheme proposed in this dissertation has provides high market efficiency when maintaining voltage security and reducing line congestions rather than a scheme using fixed violation costs. These findings suggest that the proposed schemes are cost-effective for network operation with P2P electricity trading by managing system losses, network violations.

Finally, in chapter 7, the dissertation concludes and presents future works that can be explored based on the findings and results obtained in the dissertation.

Chapter 2 Causality-based System Loss Charge

2.1 Efficiency of causality-based system loss charge

In this chapter, the method for comparing market efficiency used in [37] is applied to show that the system loss cost distribution based on the cost-causality principle is more suitable for deriving the optimal market efficiency than the equal loss allocation. For this purpose, the following assumptions are made. First, the price traded in the market is set to a fixed same value when perfectly competitive market is in equilibrium state [38]. Second, the utility function of market participant can be formulated as a concave function over the trading volume within the interval $[\underline{p}_i, \overline{p}_i]$. Finally, it is possible to distinguish the amount of contribution to the system loss according to the transaction volume of market participants and distribute the cost accordingly, i.e., the sum of individual losses generated by market participants is equal to the total system loss. Under the first and second assumptions, it is noting that the presence of a P2P electricity market as a non-cooperative game can be verified when the following criteria are met: 1) there is a finite number of players in the game; 2) the trading volume sets are closed, bounded, and convex; and 3) the utility function of market participants is both continuous and concave within the strategy space [38].

Equations (2.1) and (2.2) represent the utility functions of prosumers and consumers.

$$WP_i = \lambda^* \times p_i - \mathrm{C}_i(p_i) - c \times l_i \tag{2.1}$$

$$WC_j = \sum_{i \in N_P} U(p_{j,i}) - \sum_{i \in N_P} \lambda^* \times p_{j,i} - c \times l_j \tag{2.2}$$

Where λ^* is the fixed price in the equilibrium market, and c is the unit compensation price for the system loss caused by the transaction. $\mathrm{C_i}(p_i)$ has a convex form as a quadratic function with respect to p_i, $U(p_{j,i})$ has a concave form with respect to $p_{j,i}$, and l_i is the allocated system losses to the participants i, so the welfare function of the prosumer and consumer can be expressed as follow.

$$W_i = w_i(p_i) - c \times l_i \tag{2.3}$$

Where, $w_i(p_i)$ is the utility of prosumers and consumers for trading volume p_i, and $c \times l_i$ is the cost for system loss that market participants have to pay. According to equation. (2.3), the outcome of the market where the social net benefit is maximized can be expressed as follow.

$$W_{total}(P) = \max_{P \in \mathbb{R}^n} \sum_i w_i(p_i) - \mathrm{c} \times P_L\,(P) \tag{2.4}$$

Where, P_L is the system loss caused by the market result. If there exists a $P^* = (p_1^*, p_2^*, \ldots p_i^*, \ldots\ p_N^*)$ that leads to the optimal market outcome, then the social welfare $W(P^*)$ satisfies the stationary condition as shown in equation (2.5) for all participants i.

$$\frac{\partial W(P^*)}{\partial p_i} = \frac{\partial w_i(p_i^*)}{\partial p_i} - \mathrm{c} \times \frac{\partial P_L(P^*)}{\partial p_i} = 0 \tag{2.5}$$

In a P2P electricity market with equal loss allocation, the system losses to be compensated by market participant *i* can be formalized as equation (2.6), and the utility of market participant *i* with equal loss allocation can be defined as equation (2,7).

$$l_i = P_L(P) \times \frac{p_i}{\sum_n p_n} \tag{2.6}$$

$$W_i = w_i(p_i) - c \times P_L(P) \times \frac{p_i}{\sum_n p_n} \tag{2.7}$$

In a market with a decentralized mechanism, market participants perform trades solely in their own self-interest, so the market is determined at the Nash equilibrium point where all market participants' utility is not reduced by not changing their strategies [38]. If there exists a Nash equilibrium state $P^{*E} = (p_1^{*E}, p_2^{*E}, \dots p_i^{*E}, \dots\ p_N^{*E})$ in a market with a decentralized mechanism, then the utility function of each market participant in the Nash equilibrium state satisfies the first-order condition as shown in equation (2.8).

$$\frac{\partial w_i\left(p_i^{*E}\right)}{\partial p_i} - \mathrm{c} \times \left(\frac{\partial P_L(P^{*E})}{\partial p_i} \times \frac{p_i^{*E}}{\sum_n p_n^{*E}} + P_L(P^{*E}) \times \frac{\sum_n p_n^{*E} - p_i^{*E}}{(\sum_n p_n^{*E})^2}\right) = 0 \tag{2.8}$$

In Nash equilibrium state, in order to satisfy the optimal market effect, equations (2.5) and (2.8) must be satisfied simultaneously, which can be represented by equation (2.9).

$$\frac{\partial P_L(P^{*E})}{\partial p_i} \times \frac{\sum_n p_n^{*E} - p_i^{*E}}{\sum_n p_n^{*E}} = P_L(P^{*E}) \times \frac{\sum_n p_n^{*E} - p_i^{*E}}{(\sum_n p_n^{*E})^2} = 0 \tag{2.9}$$

$$\frac{\partial P_L(P^{*E})}{\partial p_i} = \frac{P_L(P^{*E})}{\sum_n p_n^{*E}} \tag{2.10}$$

According to equation (2.10), the optimal market outcome in Nash equilibrium state can be derived when the amount of change in system loss according to the trading volume of market participant *i* and the average of system loss over the total trading volume are equal. However, this case refers to transactions between market participants located at different nodes in a network with only two different nodes, i.e., there are only prosumers producing electricity at one node and consumers at the other node.

In a P2P electricity market where a cost causation principle is applied to distribute system loss costs according to the size of the system loss caused by the market participant's transaction, the losses to be paid by the market participant can be represented as equation (2.11), depending on the assumptions.

$$P_L = \sum_n l_n(p_n) \tag{2.11}$$

Where $l_i(p_i)$ is the system loss caused to the network by market participant i's trading volume p_i. The utility function of market participant i including this can be formalized as equation (2.12).

$$W_i = w_i(p_i) - c \times l_i(p_i) \tag{2.12}$$

If there exists a Nash equilibrium state $P^{*C} = (p_1^{*C}, p_2^{*C}, \dots p_i^{*C}, \dots\ p_N^{*C})$ in a market with cost causality-based loss allocation, then the first-order condition is satisfied for all market participants' utility functions as shown in equation (2.13).

$$\frac{\partial w_i\left(p_i^{*C}\right)}{\partial p_i} - \mathrm{c} \times \frac{\partial l_i\left(p_i^{*C}\right)}{\partial p_i} = 0 \tag{2.13}$$

Under the second assumption, the system loss is partially differentiated by p_i with respect to the sum of each market participant's contribution to the volume, which is given by equation (2.14).

$$\frac{\partial P_L(P^{*C})}{\partial p_i} = \sum_n \frac{\partial l_n(p_n^{*C})}{\partial p_n} = \frac{\partial l_i\left(p_i^{*C}\right)}{\partial p_i} \tag{2.14}$$

$$\frac{\partial W(P^{*C})}{\partial p_i} = \frac{\partial w_i\left(p_i^{*C}\right)}{\partial p_i} - \mathrm{c} \times \frac{\partial P_L(P^{*C})}{\partial p_i} = \frac{\partial w_i\left(p_i^{*C}\right)}{\partial p_i} - \mathrm{c} \times \frac{\partial l_i\left(p_i^{*C}\right)}{\partial p_i} \tag{2.15}$$

Substituting equation (2.14) into equation (2.5) is equivalent to equation (2.15), and substituting p_i^{*C} for p_i is equivalent to equation (2.13), so it satisfies the optimal market result in P2P electricity market.

2.2 Causality-based system loss charging methods

Incremental transmission loss and the Shapley value are employed for allocating causality-based system loss charge. The nonlinear nature of system losses poses a challenge in accurately attributing the impact of market participants' trading volumes. To overcome this limitation, incremental transmission loss distributes system losses by utilizing the sensitivity of system losses at specific states. Additionally, the Shapley value allocates losses by utilizing the average marginal loss for each trading volume in the grid. In other words, it approximates the influence on losses based on sensitivity and expected values.

2.2.1 Marginal loss allocation

The marginal loss allocation method distributes generated losses using the incremental transmission loss (ITL) coefficient, which represents the change in overall system loss for each node's injected power [39]. According to [40], ITL can be obtained through converged power flow analysis. First, the total system loss P_L is calculated as the difference between total generation and total consumption. As shown in equation (2.17), the bus power is then determined by summing the power injection at each node.

$$P_L = \sum_{i}^{N}(PG_i - PD_i) = \sum_{i}^{N} P_i \tag{2.17}$$

Where, PG_i, PD_i, and P_i are power generation, power consumption, and injected power at node i, respectively. If the first i is a slack bus, then according to the power flow equation, P_i can be defined as equation (2.18).

$$P_i = \sum_{k=1}^{N} |y_{i,k}| \times |V_i| \times |V_k| \times \cos(\delta_k - \delta_i + \gamma_{i,k}) \tag{2.18}$$

Where, $|y_{i,k}|, \gamma_{i,k}$ are magnitude and angle of admittance from admittance matrix. $|V_i|$, δ_i are magnitude and angle voltage at node i. By setting $|V_1|$ and δ_1 of the slack bus to 1 and 0, respectively, P_i is derived as equation (2.19) and (2.20) with the state variables.

$$P_i = P_i(\Delta), \qquad \text{for i} = 1, \ldots, \text{N} \tag{2.19}$$

$$\Delta \triangleq [\delta_2, \delta_3, \ldots, \delta_N]^T \tag{2.20}$$

In the same way, P_L can be defined as equation (2.21) with state variables.

$$P_L = P_L(\Delta) \tag{2.21}$$

From equation (2.17), equation (2.22) can be obtained through differentiation

$$dP_L = \sum_{i}^{N} dP_i = dP_1 + \sum_{i=2}^{N} dP_i \tag{2.22}$$

All of the derivatives dP_i are calculated from equation (2.18), which are given by equation (2.23)

$$\begin{aligned} dP_1 &= \frac{\partial P_1}{\partial \delta_2} \times d\delta_2 + \cdots + \frac{\partial P_1}{\partial \delta_n} \times d\delta_N \\ dP_2 &= \frac{\partial P_2}{\partial \delta_2} \times d\delta_2 + \cdots + \frac{\partial P_2}{\partial \delta_n} \times d\delta_N \\ &\vdots \\ dP_n &= \frac{\partial P_n}{\partial \delta_2} \times d\delta_2 + \cdots + \frac{\partial P_n}{\partial \delta_n} \times d\delta_N \end{aligned} \tag{2.23}$$

To simplify the above expression, the following vectors of $(n-1)$ dimension is defined as equation (2.24), (2.25), and (2.26).

$$d\mathrm{P} \triangleq [dP_2, dP_3, \dots, dP_N]^T \tag{2.24}$$

$$\frac{\partial P_1}{\partial \Delta} \triangleq \left[\frac{\partial P_1}{\partial \delta_2}, \frac{\partial P_1}{\partial \delta_3}, \dots, \frac{\partial P_1}{\partial \delta_N}\right]^T \tag{2.25}$$

$$d\Delta \triangleq [d\delta_2, d\delta_3, \dots, d\delta_N]^T \tag{2.26}$$

Equation (2.27) is defined as $(n-1) \times (n-1)$ jacobian matrix.

$$\frac{\partial P}{\partial \Delta} \triangleq \begin{bmatrix} \frac{\partial P_2}{\partial \delta_2} & \cdots & \frac{\partial P_2}{\partial \delta_N} \\ \vdots & \ddots & \vdots \\ \frac{\partial P_N}{\partial \delta_2} & \cdots & \frac{\partial P_N}{\partial \delta_N} \end{bmatrix} \tag{2.27}$$

Utilizing the matrices and vectors we have defined, equation (2.23) can be rewritten into the following compact form.

$$dP_1 = \left(\frac{\partial P_1}{\partial \Delta}\right)^T \cdot d\Delta, \qquad dP = \frac{\partial P}{\partial \Delta} \cdot d\Delta \tag{2.28}$$

To find dP_1 in equation (2.28), the inverse of $\frac{\partial \mathbb{p}}{\partial \bar{\bar{\delta}}}$ is derived as follow.

$$\begin{aligned} dP_1 &= \left(\frac{\partial P_1}{\partial \Delta}\right)^T \cdot \left(\frac{\partial P}{\partial \Delta}\right)^{-1} \cdot dP \triangleq A \cdot dP \\ A &\triangleq \left(\frac{\partial P_1}{\partial \Delta}\right)^T \cdot \left(\frac{\partial P}{\partial \Delta}\right)^{-1} = [A_2, A_3, \dots, A_N] \end{aligned} \tag{2.29}$$

the following expression can be derived by substituting equation (2.30) into equation (2.22).

$$\begin{aligned} dP_L &= A \cdot dP + \sum_{i=2}^{N} dP_i \\ &= (1 + A_2)dP_2 + (1 + A_3)dP_3 + \cdots + (1 + A_N)dP_N \end{aligned} \tag{2.30}$$

Equation (2.31) gives the incremental change in system loss (ITL) for the incremental change in injected power on each bus.

$$\begin{aligned} &\frac{dP_L}{dP_i} \triangleq \frac{\partial P_L}{\partial P_i} \triangleq (ITL)_i = 1 + A_i = \phi_{m,i}, \qquad for\ i = 2, \dots, N \\ &(ITL)_1 = 0 \end{aligned} \tag{2.31}$$

However, if ITL derived in this way is used for loss allocation, it may not result in an accurate distribution. Nonlinearities in the system can cause a difference between the calculated total loss and the actual loss. Therefore, a normalization process is required to consider the actual loss amount as shown in equation (2.32) [39] , and the unit loss charge can be defined as $c \times \frac{\phi_{m,n}}{P_n}$.

$$P'_L = P'_L \times \frac{P_L}{P'_L} = (\sum_{i=1}^{N_p} ITL_{Gi} \times P_{Gi} - \sum_{i=1}^{N_c} ITL_{Gi} \times P_{Di}) \times \frac{P_L}{P'_L} \quad (2.32)$$

Where P'_L represents the actual system loss. If the value of ITL in the generation node is positive, the loss price is charged as the system loss increases. Conversely, if the ITL value is negative, the system loss will decrease as the generation increases, resulting in a negative loss price. In the case of consumption, if ITL is positive, the system loss decreases as consumption increases, resulting in a negative loss price. However, if ITL is negative, the loss will increase as consumption increases. Table 3 summarizes the meaning of ITL at the generation and consumption node.

Table 3 Summary of meaning of ITL according to node type

Node	ITL	Description
P_{Gi}	Positive	Loss is charged for increasing the system loss
	Negative	Loss is compensated by decreasing the system loss
P_{Di}	Positive	Loss is compensated by decreasing the system loss
	Negative	Loss is charged for increasing the system loss

2.2.2 Shapley value for loss allocation

Shapely value is the quantification of the contribution of an individual participant in a game. In cooperative games, every player in a group has a certain role in maximizing the total payoff of the group. Lloyd Shapley proposed the concept of values in 1953 to define the importance and contributions of individual players within a group. Some players may have a value of zero when playing alone, but may have greater value when forming coalitions. Therefore, players in the game will form coalitions if the value of the coalition is greater than the sum of the values of the individual players. The Shapley value provides a unique solution for each player and satisfies four axioms of fairness: efficiency, symmetry, dummy property, and additivity. Assuming that the number of players in the cooperative game is n and that the grand coalition is formed by N = {1, 2, ..., n}, the total number of coalitions is $2^{\mathrm{n}} - 1$, excluding the null or empty coalition as shown as equation (2.34).

$$\phi_i(v) = \sum_{\substack{S \subseteq N \\ i \in S}} \frac{(|S| - 1)! \times (n - |S|)!}{n!} \times [v(S) - v(S - \{i\})] \tag{2.34}$$

Where $|S|$ is the number of players in coalitions S, $v(S)$ is the characteristic function value meaning the gain of a coalition S, which is a subset of N ($S \subset N$) and, $v(S - \{i\})$ is the gain of a coalition S excluding player i.

However, in order to obtain the Shapley value of the system loss for the amount of power applied to a specific node, it is necessary to find all the coordination combinations for the node and solve the power flow equation for it. Therefore, in this study, a loss allocation method using Shapley value is used to reflect the characteristics of radial distribution network [41].

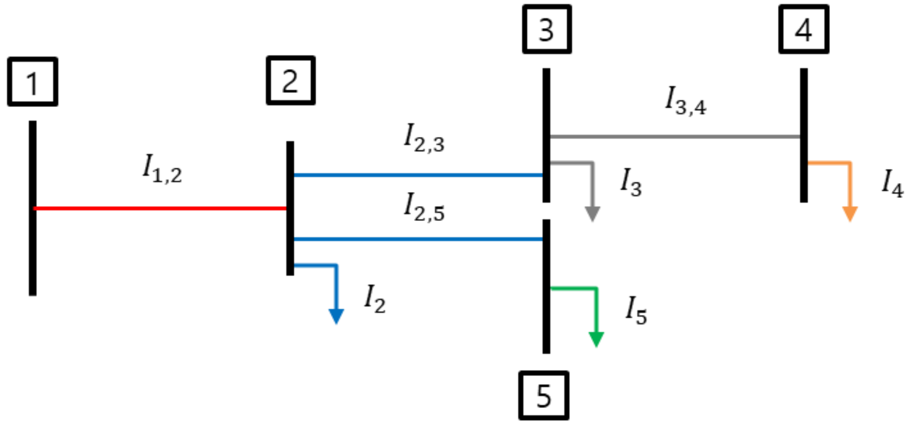

Figure 4 A sample 5 bus radial distribution network.

The network in Figure 4 shows the example for computation of loss allocation using Shapley value. Assuming the complex branch current ($I_{1,2}, I_{2,3}, I_{3,4}, I_{2,5}$) and complex load current (I_2, I_3, I_4, I_5), define the relation between branch current and node current as equation (2.35).

$$
\begin{aligned}
I_{1,2} &= I_2 + I_3 + I_4 + I_5 \\
I_{2,3} &= I_3 + I_4 \\
I_{3,4} &= I_3 \\
I_{2,5} &= I_4
\end{aligned}
\tag{2.35}
$$

Setting the branch resistance as ($R_{1,2}, R_{2,3}, R_{3,4}, R_{2,5}$), the active power losses of branch 1 to 2 can be formulated as equation (2.36)

$$
\begin{aligned}
&P_L(I_{1,2}) \\
&= |I_{1,2}|^2 \times R_{1,2} \\
&= |I_2 + I_3 + I_4 + I_5|^2 \times R_{1,2} \qquad (2.36) \\
&= Re(I_{1,2}^2) \times R_{1,2} + Im(I_{1,2}^2) \times R_{1,2} \\
&= P_{LR}(I_{1,2}) + P_{LI}(I_{1,2})
\end{aligned}
$$

The active power losses are separated into the real and imaginary components $(\mathrm{P_{LR}}(I_{1,2}), \mathrm{P_{LI}}(I_{1,2}))$ of the branch current $I_{1,2}$. Because there are no cross terms between real and imaginary components of the current and Shapley value has the additivity property, Find the Shapley value for each component and combine them to get the original the Shapley value as equation (2.37).

$$\phi(P_{LR}(I_{1,2}) + P_{LI}(I_{1,2})) = \phi(P_{LR}(I_{1,2})) + \phi(P_{LI}(I_{1,2})) \qquad (2.37)$$

As $I_{1,2} = I_{2,3} + I_{2,5} + I_2$, real components of losses in branch 12 can be represented as equation (2.38) with $Re(I_{1,2R}) = Re(I_{2,3}) + Re(I_{2,5}) + Re(I_2)$

$$P_{LR}(I_{12}) = \left(Re(I_{2,3}) + Re(I_{2,5}) + Re(I_2)\right)^2 \times R_{1,2} \qquad (2.38)$$

If $Re(I_{2,3}), Re(I_{2,5})$ and, $Re(I_2)$ are considered as players contributing to the coalition of $\mathrm{P_{LR}}(I_{1,2})$, the Shapley value of system loss for each player can be calculated using equation (2.39).

$$
\begin{aligned}
\phi_{Re(I_2)} &= Re(I_2) \times (Re(I_{2,3}) + Re(I_{2,5}) + Re(I_2)) \times R_{12} \\
&= Re(I_2) \times Re(I_{1,2}) \times R_{1,2} \\
\phi_{Re(I_{2,3})} &= Re(I_{2,3}) \times (Re(I_{2,3}) + Re(I_{2,5}) + Re(I_2)) \times R_{1,2} \\
&= Re(I_{2,3}) \times Re(I_{1,2}) \times R_{1,2} \\
\phi_{I_{2,5}} &= Re(I_{2,5}) \times (Re(I_{2,3}) + Re(I_{2,5}) + Re(I_2)) \times R_{1,2} \\
&= Re(I_{2,5}) \times Re(I_{1,2}) \times R_{1,2}
\end{aligned} \tag{2.39}
$$

The same procedure can be repeated for branch 23. In this case, the losses in the grid caused by the current flowing in branch 23 are caused by the coordination of $Re(I_3)$ and $Re(I_{3,4})$, which can be expressed as equation (2.40).

$$
\begin{aligned}
\phi_{Re(I_3)} &= Re(I_3) \times Re(I_{2,3}) \times R_{2,3} + Re(I_3) \times Re(I_{1,2}) \times R_{1,2} \\
\phi_{Re(I_{3,4})} &= Re(I_{3,4}) \times Re(I_{2,3}) \times R_{2,3} + Re(I_{3,4}) \times Re(I_{1,2}) \times R_{1,2}
\end{aligned} \tag{2.40}
$$

If the Shapley value of the system loss of the power injected into the node at the lower level is obtained through this method, the contribution to the system loss at each node can be calculated as equation (2.41), and the unit loss charge is defined as $c \times \frac{\phi_{s,n}}{P_n}$.

$$
\begin{aligned}
&P_L = \left(\phi_{s,2} + \phi_{s,3} + \cdots + \phi_{s,N}\right) \\
&c \times P_L = c \times \left(\frac{\phi_{s,2}}{P_2} \times P_2 + \frac{\phi_{s,3}}{P_3} \times P_3 + \cdots + \frac{\phi_{s,N}}{P_N} \times P_N\right)
\end{aligned} \tag{2.41}
$$

Chapter 3 Network Operation Scheme with System Loss Charge

System loss management scheme of the DSO for P2P electricity trading is depicted in figure 5. Prosumers and consumers engage in transactions by exchanging trading information to maximize their welfare. The DSO estimates the system losses using the trading information and sets the system loss allocation prices based on the cost-causality principle to distribute the system loss cost among the participants. The DSO notifies the system loss allocation prices to the prosumers and consumers, who then adjust a trading strategy considering the loss cost they may have to pay and continue trading until they reach an agreement. Thus, the DSO offers price signals to market participants for continuous and repeated system losses to guide trading results towards minimizing system losses. In other words, the DSO continuously and repeatedly provide price signals for system losses while market participants are executing trades to guide trade outcomes in a way that minimizes system losses.

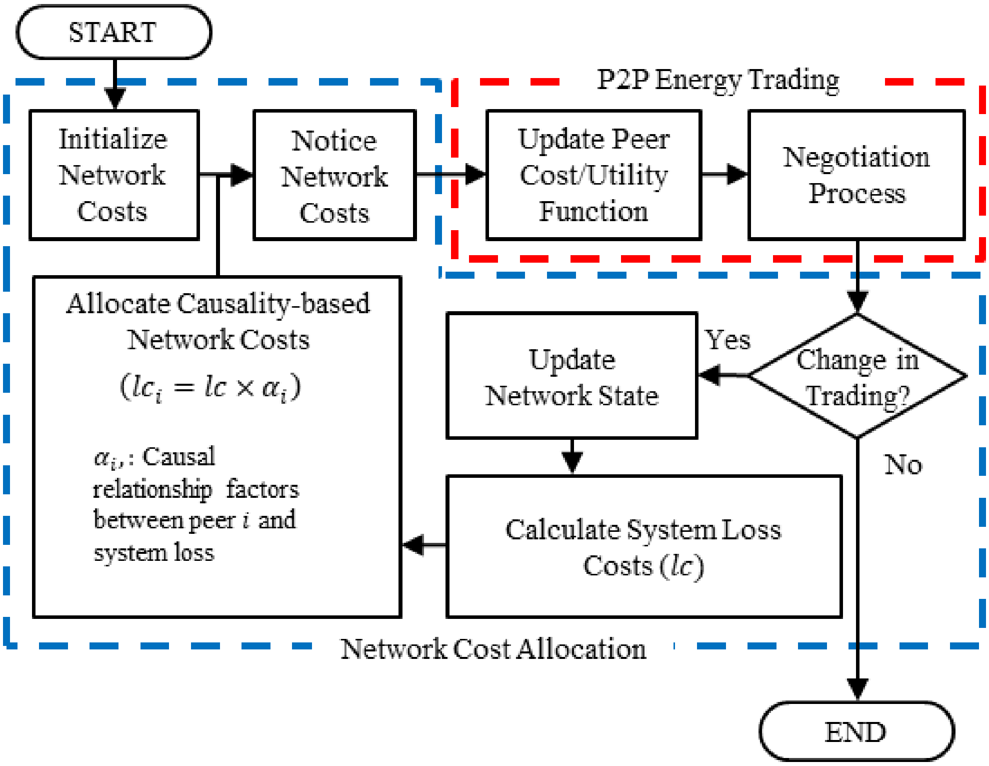

Figure 5 Illustrating P2P electricity trading process with causality-based system loss charge

3.1 Modeling of market participants

P2P electricity trading is set up as a real-time market for trading electricity for delivery at a specific point in time. It is assumed that multiple market participants simultaneously exchange information for trading for their own benefit, and there are no synchronized time constraints. Prosumers connected to the network can sell additional surplus electricity through Feed in Tariff (FiT), but this is not considered in this study. Consumers can also purchase surplus electricity from utilities as well as P2P electricity markets, but this study only considers the results of P2P electricity trading. This article focuses on a deterministic clearing mechanism for a single market price time slot, which can be easily extended to multiple time slots. The time slot is assumed to be one hour. In the market, market participants set N is composed of a set of $N_P = \{1,2,3,\dots,n_p\}$ for prosumers and $N_C = \{1,2,3,\dots,n_c\}$ for Consumers. All prosumers belong to $\mathrm{N_P}$ and all consumers belong to N_C. Thus, $N_P \cup N_C = N$ and $N_P \cap N_C = \phi$.

3.1.1 Prosumer model

The cost function of prosumer $C_i(p_i)$ is formed as a quadratic convex function power p_i represented in [42] as equation (3.1).

$$C_i(p_i) = a_i \times p_i^2 + b_i \times p_i + c_i \tag{3.1}$$

Where, parameters of cost function a_{i}, b_i, c_i are essential for determining the quantity of electricity that a seller is willing to sell at different prices and times. These constants are unique to each seller and depend on factors such as their generation type, load, and future risk, making them critical for efficient and effective electricity trading. Hence, accurate estimation and prediction of these parameters are crucial for optimizing P2P electricity trading systems. The welfare of prosumer i is modeled by equation (3.2)

$$WP_i = \lambda_i \times p_i - \mathrm{C_i}(p_i) - lc_i(p_i) \tag{3.2}$$

Where, λ_i is the traded price, the first term $\lambda_i \times p_i$ in equation (3.2) represents the income of prosumer i through the electricity trading, the second term indicates the generation cost, and $lc_i(p_i)$ is loss cost for compensating system loss due to generation p_i. In addition, generation of prosumer i reflects the following physical constraints as equation (3.3).

$$\underline{p_i} \leq p_i \leq \overline{p_i}, \qquad \forall \mathrm{i} \in \mathrm{N_P} \tag{3.3}$$

Where, $\underline{p_i}$ and $\overline{p_i}$ are the minimum and maximum generation of prosumer i, respectively.

3.1.2 Consumer model

The utility function defines the satisfaction level of the consumer over a set of goods and services. The utility function of a consumer participating in a P2P electricity market is a measure of the consumer's satisfaction with the amount of electricity purchased through a transaction. In general, the utility function of consumer j, which is denoted by $\mathrm{U_j}(p_j)$ has the following characteristics [43, 44].

- $\frac{\mathrm{dU_j}(p_j)}{\mathrm{d}p_j} \geq 0$, i.e., the utility function is a nondecreasing
- $\frac{\mathrm{d^2U_j}(p_j)}{\mathrm{d}p_j^2} \geq 0$, i.e., the utility function will be saturated.
- $\mathrm{U_j}(p_j) = 0$, i.e., there is no satisfaction, without consumption

The consumer's utility function for a consumer j satisfying these properties is modeled as equation (3.4).

$$\mathrm{U_j}(p_j) = \begin{cases} \beta_j \times p_j - \frac{\alpha_j}{2} \times p_j^2, & 0 \leq p_j \leq \frac{\beta_j}{\alpha_j} \\ \frac{\beta_j^2}{2 \times \alpha_j}, & p_j \geq \frac{\beta_j}{\alpha_j} \end{cases} \tag{3.4}$$

Where, α_j and β_j are parameters of utility function, which are the private information of consumer j. Consumer can buy electricity from any prosumer in the P2P electricity market and the welfare of consumer j is defined as the utility of the electricity consumption minus payment of purchase and loss cost as formulated in equation (3.5) and (3.6)

$$WC_j = \sum_{i \in N_P} U(p_{j,i}) - \sum_{i \in N_P} \lambda_i \times p_{j,i} - lc_j(p_j) \tag{3.5}$$

$$p_j = \sum_{i \in N_P} p_{j,i} \tag{3.6}$$

and the total electricity consumption is bounded as equation (3.7).

$$\underline{p_j} \leq p_j \leq \overline{p_j}, \qquad \forall \mathrm{j} \in \mathrm{N_C} \tag{3.7}$$

3.1.3 Allocating system loss charge

In order to allocate loss charges, the DSO needs to calculate system losses using the trading volume information of market participants. In this dissertation, linearized distribution flow is employed to ensure efficiency and convexity in the calculation of system losses, thereby guaranteeing converged market outcomes [45].

$$p_n = \begin{cases} p_i - p_j, & i = j, \forall n \in N \\ p_n = p_i \ \ or \ \ p_n = -p_j, & i \neq j, \forall n \in N \end{cases} \tag{3.8}$$

$$q_n = \begin{cases} q_i - q_j, & i = j, \forall n \in N \\ q_n = q_i \ \ or \ \ q_n = -q_j, & i \neq j, \forall n \in N \end{cases} \tag{3.9}$$

Equation (3.8) and (3.9) represent the conversion of trading volume information of market participants into network node injected power.

$$p_n = \sum_l A(n,l) \times p_l - \sum_l B(n,l) \times pl_l \tag{3.10}$$

$$q_n = \sum_l A(n,l) \times q_l - \sum_l B(n,l) \times ql_l \tag{3.11}$$

Equations (3.10) and (3.11) represent the line flow for the injected power at each node. In these equations, A(n, l) and B(n, l) denote the incidence matrix of the distribution network. Specifically, A(n, l) = 1 and B(n, l) = 0 if node n is the sending node of line l, while A(n, l) = 1 and B(n, l) = -1 if node n is the receiving node of line l.

$$pl_l = \frac{p_l^2 + q_l^2}{v_{s,l}^2} \times R_l,\ ql_l = \frac{p_l^2 + q_l^2}{v_{s,l}^2} \times X_l \tag{3.12}$$

Equation (3.12) represents the active power loss pl_l and reactive power loss ql_l occurring in each line l.

$$v_{s,l}^2 - v_{r,l}^2 = 2 \times R_l \times p_l + 2 \times X_l \times q_l - R_l \times pl_l - X_l \times ql_l \tag{3.13}$$

Equation (3.13) represents the voltage difference between the sending and receiving nodes of line l.

$$\delta_l = X_l \times p_l - R_l \times q_l \tag{3.14}$$

Equation (3.14) represents the phase difference between the sending and receiving nodes of line l.

$$lp_i = \phi_i \times \Lambda \times \sum_l pl_l \tag{3.15}$$

Using the above equation, the system losses are estimated, and then equation (3.15) is used to set the unit cost for the system loss charge. In this case, ϕ_i represents the allocation factors set for market participant i to distribute the system loss charge, which can be based on incremental transmission loss allocation or Shapley value-based loss allocation.

3.2 Negotiation process with system loss charge

During each electricity trading in the market, each market participant acts in a non-cooperative manner for their own purposes, and the objective function of the market is the sum of individual utilities maximized, which can be represented as equation (3.16).

$$\max_{p_i, p_j} \left(\sum_{i}^{N_P} WP_i(p_i) + \sum_{j}^{N_C} WC_j(p_j) \right) \tag{3.16}$$

Where WP_i and WC_j are welfare of prosumer i and consumer j, respectively. p_i and p_j are generation of prosumer i and consumption of consumer j. Trading volume between prosumer and consumer should be balanced in the P2P market which is represented by equation (3.17)

$$p_i = \sum_{j \in N_C} p_{j,i}, \qquad \forall \mathrm{i} \in \mathrm{N_P} \tag{3.17}$$

the objective function in equation (3.16) is a convex problem and should be maximized subject to equations (3.3), (3.6), (3.7) and (3.17) as shown equation (3.18).

$$\max_{p_i, p_j} \left(\sum_{i}^{N_P} WP_i(p_i) + \sum_{j}^{N_C} WC_j(p_j) \right)$$

$subject\ to$

$$WP_i = \lambda_i \times p_i - C_i(p_i) - lp_i \times p_i$$

$$WC_j = \sum_{i \in N_P} \left[U(p_{j,i}) - \lambda_i \times p_{j,i} - lp_j \times p_{j,i} \right] \tag{3.18}$$

$$p_i = \sum_{j \in N_C} p_{j,i}, \ \forall i \in N_P$$

$$\underline{p_j} \le p_j \le \overline{p_j}, \ \ \forall j \in N_C$$

$$\underline{p_i} \le p_i \le \overline{p_i}, \ \ \forall i \in N_P$$

In a conventional power market, this problem is solved by a centralized mechanism, where the market operator derives the optimal market result by synthesizing information related to the transactions of all market participants and the network. However, since this study considers a P2P electricity market in which the market is operated solely by transactions between market participants in the absence of centralized control, we solve equation (3.18) using a decentralized optimization algorithm that can derive market results by exchanging transaction information between market participants.

According to [46], the optimal problem can be transformed into a Lagrange dual problem, which can then be solved by the Dual Ascent method. Under the assumption of strong duality, we define the Lagrange function and the dual function for the primal problem, and use the gradient method to find the solution of the dual function problem. The solution of the dual function is then used to solve the original problem by finding the dual solution using the dual ascent method. The greatest advantage of the dual ascent method is that it can lead to a decentralized algorithm in certain scenarios. For instance, assuming that the objective function f is separable, i.e., related to dividing variables or dividing into sub-vectors, the dual ascent method can provide a viable decentralized approach. To apply the decentralized mechanism, equation (3.18) would be transformed into the Lagrange dual problem as equation (3.19).

$$
\begin{aligned}
& D\left(\lambda_i, \overline{\mu_i}, \underline{\mu_i}, \overline{\nu_j}, \underline{\nu_j}, \overline{\xi_l}, \underline{\xi_l}\right) \\
& = \min_{p_i, p_{ji}} L\left(p_i,\ p_{ji},\ \lambda_i, \overline{\mu_i}, \underline{\mu_i}, \overline{\nu_j}, \underline{\nu_j}\right) \\
& = \sum_j^{N_C} \sum_i^{N_P} \left(U\left(p_{j,i}\right) - lp_j \times p_{j,i}\right) - \sum_i^{N_P} \left(C_i(p_i) + lp_i \times p_i\right) \\
& + \sum_i^{N_P} \lambda_i \times \left(p_i - \sum_{j \in N_C} p_{j,i}\right) \\
& + \sum_i^{N_P} \overline{\mu_i} \times \left(\overline{p_i} - p_i\right) + \sum_i^{N_P} \underline{\mu_i} \times \left(p_i - \underline{p_i}\right) \\
& + \sum_j^{N_C} \overline{\nu_j} \times \left(\overline{p_j} - \sum_{i \in N_P} p_{j,i}\right) + \sum_j^{N_C} \underline{\nu_j} \times \left(\sum_{i \in N_P} p_{j,i} - \underline{p_j}\right)
\end{aligned}
\tag{3.19}
$$

Where $\lambda_i, \overline{\mu_i}, \underline{\mu_i}, \overline{\nu_j}, and\ \underline{\nu_j}$ are the largrangian multipliers for constraints (3.17), (3.3), and (3.7). The largrangian dual problem can be partitioned into separate problems for the variables p_i and $p_{j,i}$, which can be expressed in the form as shown equation (3.12) to (3.26)

$$D_i\left(\lambda_i^k, \overline{\mu_i}^k, \underline{\mu_i^k}\right)$$
$$= \underset{p_i}{argmax}\left[\lambda_i^k \times p_i - C_i(p_i) - lp_i^k \times p_i + \left(\underline{\mu_i}^k - \overline{\mu_i}^k\right) \times p_i\right] \tag{3.20}$$

$$D_{ji}\left(\lambda_i^k, \overline{\nu_j}^k, \underline{\nu_j}^k\right)$$
$$= \underset{p_{ji}}{argmax}\left[U(p_{j,i}) - \lambda_i^k \times p_{j,i} - lp_j^{\mathrm{k}} \times p_{j,i} + \left(\underline{\nu_j}^k - \overline{\nu_j}^k\right) \times p_{j,i}\right] \tag{3.21}$$

$$\lambda_i^{k+1} = \left[\lambda_i^k - k \times \nabla_{\lambda_i} D\right]^+ = \left[\lambda_i^k - k \times \left(p_i^k - \sum_{j \in N_C} p_{j,i}^k\right)\right]^+ \tag{3.22}$$

$$\overline{\mu_i}^{k+1} = \left[\overline{\mu_i}^k - k \times \nabla_{\overline{\mu_i}} D\right]^+ = \left[\underline{\mu_i}^k - k \times \left(p_i^k - \underline{p_i}\right)\right]^+ \tag{3.23}$$

$$\underline{\mu_i}^{k+1} = \left[\underline{\mu_i}^k - k \times \nabla_{\underline{\mu_i}} D\right]^+ = \left[\underline{\mu_i}^k - k \times (p_i^k - \underline{p_i})\right]^+ \tag{3.24}$$

$$\overline{\nu_j}^{k+1} = \left[\overline{\nu_j}^k - k \times \nabla_{\overline{\nu_j}} D\right]^+ = \left[\overline{\mu_i}^k - k \times (\overline{p_j} - \sum_{i \in N_P} p_{j,i}^k)\right]^+ \tag{3.25}$$

$$\underline{\nu_j}^{k+1} = \left[\underline{\nu_j}^k - k \times \nabla_{\underline{\nu_j}} D\right]^+ = \left[\underline{\mu_i}^k - k \times (\sum_{i \in N_P} p_{j,i}^k - \underline{p_j})\right]^+ \tag{3.26}$$

Where, the generation (p_i) that maximizes prosumer i's gain for trading price (λ_i) is determined by $D_i\left(\lambda_i, \overline{\mu_i}, \underline{\mu_i}\right)$. Likewise, $D_{ji}\left(\lambda_i, \overline{\nu_j}, \underline{\nu_j}\right)$ determines the purchase quantity ($p_{j,i}$) that maximizes consumer j's utility from prosumer i for transaction price (λ_i). To obtain the optimal value, the gradient descent method is used, which derives the direction of the optimal values of $D_i\left(\lambda_i, \overline{\mu_i}, \underline{\mu_i}\right)$ and $D_{ji}\left(\lambda_i, \overline{\nu_j}, \underline{\nu_j}\right)$ through the directional derivative of the Lagrangian dual problem for the Lagrangian multipliers. The converged optimal value is obtained by repeating the process of obtaining $p_i, p_{j,i}$, and utilizing them to update the Lagrangian multipliers.

The trading process between prosumers and consumers in the P2P electricity market is carried out according to Algorithm 1 and Algorithm 2. First, the prosumer sets the trading price (${\lambda_i}^{k+1}$) and delivers it to all consumers participating in the market. Simultaneously, it determines the generation (p_i^{k+1}) that maximizes the profit for the transaction price (${\lambda_i}^{k+1}$). Each consumer then determines the optimal purchase quantity ($p_{j,i}^{k+1}$) for the transaction price (${\lambda_i}^{k+1}$) and passes it back to the prosumer. The prosumer updates the trading price using all consumers' purchases ($p_{j,i}^{k+1}$), the updated production (p_i^{k+1}), and equation (3.22). Additionally, equations (2.23) and (2.24) are used to update $\overline{\mu_i}^{\mathrm{k+1}}$ and $\underline{\mu_i}^{\mathrm{k+1}}$ to ensure that the capacity constraints are not violated. This process is then repeated until the trading price is converged.

According to Algorithm 2, after receiving the transaction price (${\lambda_i}^{k+1}$) and determining the optimal purchase amount ($p_{j,i}^{k+1}$), the consumer updates the lagrangian multipliers $\overline{\nu_j}^{\mathrm{k+1}}$ and $\underline{\nu_j}^{\mathrm{k+1}}$ using equations (3.25) and (3.26) to avoid violating the network constraints on the purchase amount. Then, as with the prosumer, this process is repeated until $\overline{\nu_j}$ and $\underline{\nu_j}$ are converged.

Algorithm 3 describes the process by which the DSO estimates the state of the grid at each moment of transaction, determines the losses incurred by the grid, sets the compensation price, and communicates it to market participants. Specifically, the DSO determines the state of the network by using the updated purchase amount of the consumer after receiving the transaction price. The sum of the updated purchase amount of the consumer is treated as the load of the temporarily set node where the consumer is located, and the power generation of the prosumer is calculated under the assumption that the consumer's purchase amount is fully produced by the prosumer. Through this, the DSO estimates the grid losses incurred by the grid through power flow analysis and determines the loss price or equalization price according to the loss-inducing principle defined earlier. The DSO then communicates the loss price to both the prosumer and the consumer. This loss price will be taken into account when prosumers and consumers use equations (3.20) and (3.21) to determine the optimal production and purchase quantities. This process is repeated until the transaction is completed.

Algorithm 1: Trading algorithm for prosumers

1: **Input** Purchase volume of consumer (j): $p_{j,i}^{k+1}$
2: **Repeat**
3: Notify trading prices: ${\lambda_i}^{k+1}$
4: Update optimal sales volume subject to trading price: p_i^{k+1}
5: Confirm purchase volume from consumers $p_{j,i}^{k+1}$
6: Update trading prices: ${\lambda_i}^{k+1}$
7 Update Lagrangian multipliers: ${\overline{\mu_i}}^{k+1}, {\underline{\mu_i}}^{k+1}$
8: **until** $\left|{\lambda_i}^{k+1} - {\lambda_i}^{k}\right| \leq \epsilon_\lambda$

Algorithm 2: Trading algorithm for Consumers

1: **Input** Trading price of prosumer (i): ($\lambda_i{}^{k+1}$)

2: **Repeat**

3: Receive trading price form prosumer: $\lambda_i{}^{k+1}$

4: Update and broadcast optimal purchase volume: $p_{j,i}^{k+1}$

5: Update Lagrangian multipliers: $\overline{\nu_j}^{k+1}, \underline{\nu_j}^{k+1}$

6: **until** $\left|\overline{\nu_j}^{k+1} - \overline{\nu_j}^{k}\right| \leq \epsilon_\nu$ and $\left|\underline{\nu_j}^{k+1} - \underline{\nu_j}^{k}\right| \leq \epsilon_\nu$

Algorithm 3: Loss charge allocation by DSO

1: **Input** Purchase volume ($p_{j,i}^{k+1}$) of Consumer (j)

2: **Repeat**

3: Calculate total purchase volume of consumer using $p_{j,i}^{k+1}$: $\sum_{i \in N_P} p_{j,i}$

4: Estimate prosumer’ s generation output using $p_{j,i}^{k+1}$

5: Calculate and notice the loss allocation price (lp_i^{k+1}, lp_j^{k+1})

6: **until** End of transactions

Chapter 4 Network Operation Scheme with Violation Charge

The network operation scheme with violation charge for P2P electricity trading is presented in Figure 6. As with the operation scheme with system loss charge describe in chapter 3, prosumers and consumers participate in transactions through a decentralized market mechanism. The DSO obtains the transaction information exchanged between prosumers and consumers to estimate the network state and detect network violations such as line congestion and voltage violation. If a network violation is identified, the DSO imposes violation charge on the participants, leading to prosumers and consumers adjusting their trading volume. Following the cost-causality principle, the violation charge is allocated based on the contribution of the prosumer and consumer's transaction volume to the network violation by using sensitivity factor. In other words, prosumers and consumers who engage in transactions that cause a high level of network violation will be subjected to more significant violation charge.

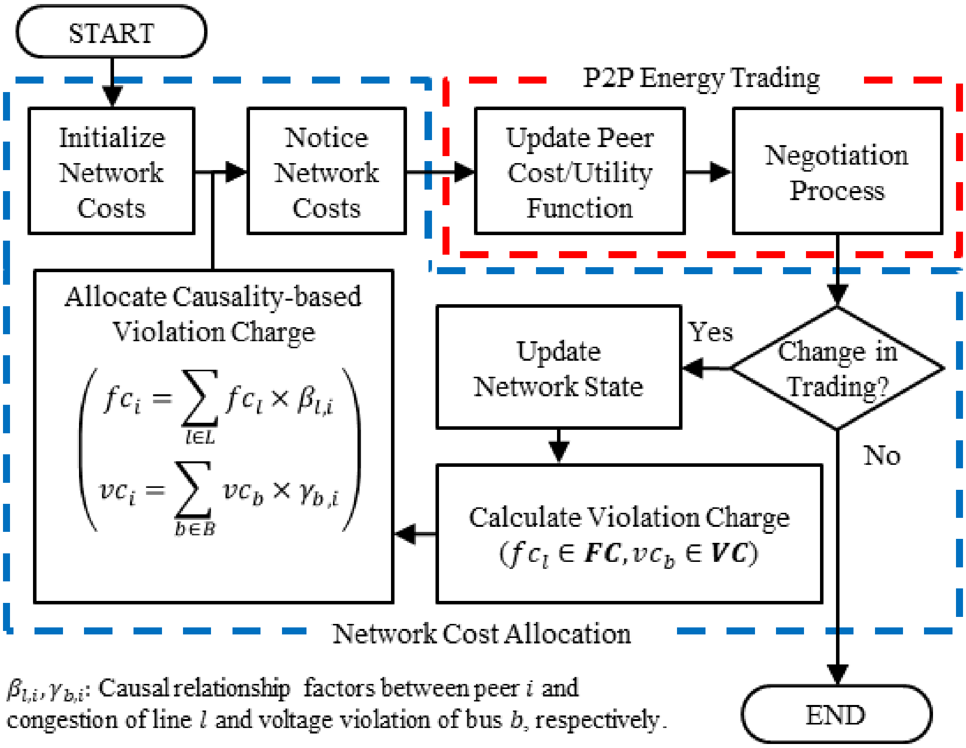

Figure 6 Illustrating P2P electricity trading process with causality-based violation charge

4.1 Sensitivity factors

Sensitivity is used to estimated network state and distribute penalties for line congestion and voltage violations, which are network violations caused by transactions. For the rest of the analysis, it is considered the network as compose of S slack and N nodes with PQ injection, (i.e., {1,2,3⋯, n, m⋯, M} =S∪N, with S∩N =∅), l∈ L lines between node i and j.

4.1.1 Voltage sensitivity factors

According to [47], the sensitivity of each node voltage to the injected active power of a node can be derived through an analytical method as follows. A node injection is considered to be constant and independent of voltage. It is assumed that for each separate disturbance of node injections, the other loads generators do not change their output. Consequently, the calculation of sensitivity inherently explains the overall response of the network from the point of view of the variation of active and reactive power flows. This result allows to calculate the sensitivities near the network state. Based on the power flow equation, the relationship between apparent power and node voltages at any node n can be represented by equation 4.1.

$$s_n^* = v_n^* \times \sum_{j \in S \cup \mathrm{N}}^{n} Y_{n,j} \times v_j \,, \qquad n \in \mathrm{N} \tag{4.1}$$

Equation (4.1) is maintained for all phases of each node in the network. The aim is to calculate the partial derivations of voltage magnitude over the active power injected in other buses. However, the voltage at the slack node always remains constant regardless of changes in other nodes in the network. Thus, it can be represented using equation (4.2) that the slack node has no change for a given variation in the injected active power at any other node in the network.

$$\frac{\partial v_n}{\partial p_m}, \qquad \forall n \in \mathrm{S} \tag{4.2}$$

In order to derive the mathematical closed-form for voltage sensitivity coefficients with respect to injected active power of a node in the network, the partial derivatives of the voltage with respect to the active power P_m of a node $m \in N$ can be derived as equation (4.3) and (4.4) using equation (4.1).

$$\mathbb{1}_{\{\mathrm{i=m}\}} = \frac{\partial v_n^*}{\partial p_m} \times \sum_{j \in S \cup \mathrm{N}}^{n} Y_{n,j} \times v_j + v_n^* \times \sum_{j \in \mathrm{N}}^{n} Y_{n,j} \times \frac{\partial v_j}{\partial p_m} \tag{4.3}$$

$$\frac{\partial s_n^*}{\partial p_m} = \frac{\partial (p_n - jq_n)}{\partial p_m} = \mathbb{1}_{\{\mathrm{i=m}\}} \tag{4.4}$$

Equation (4.3) shows linearity with respect to $\frac{\partial v_n}{\partial p_m}$ and $\frac{\partial v_n^*}{\partial p_m}$ in rectangular coordinates. According to [47], there is a unique solution for calculating partial derivatives in rectangular coordinates. the values of $\frac{\partial v_n}{\partial p_m}$ and $\frac{\partial v_n^*}{\partial p_m}$ are derived and substituted into equation (4.5) to finally obtain the voltage sensitivity coefficient and voltage sensitivity matrix VS of size (N-1)× (N-1).

$$vs_{n,m} = \frac{\partial |v_n|}{\partial p_m} = \frac{1}{|v_n|} \times \mathrm{Re}\left(v_n^* \times \frac{\partial v_n}{\partial p_m} \right)$$

$$VS = \begin{bmatrix} vs_{2,2} & \cdots & vs_{2,N} \\ \vdots & \ddots & \vdots \\ vs_{N,2} & \cdots & vs_{N,N} \end{bmatrix} \tag{4.5}$$

4.1.2 Line flow sensitivity factors

Line flow sensitivity is defined as the amount of change in line flow due to a change in injected active power at node m where random consumers and prosumers are located. According to [48], line flow sensitivity factors with respect to injected power $FS_{l,m}$ can be derived using partial differentiation and the chain rule as follows.

$$|sf_l|^2 = p_l^2 + q_l^2 \tag{4.6}$$

$$FSP_{l,m} = \frac{\partial |sf_l|}{\partial p_m} = (p_l \times \frac{\partial p_l}{\partial p_m} + q_l \times \frac{\partial q_l}{\partial p_m}) \tag{4.7}$$

$$FSQ_{l,m} = \frac{\partial |sf_l|}{\partial q_m} = (p_l \times \frac{\partial p_l}{\partial q_m} + q_l \times \frac{\partial q_l}{\partial q_m}) \tag{4.8}$$

Where, sf_l, p_l, q_l are apparent flow, active flow, and reactive flow in line l between node i and j, respectively, and partial differentiation terms are defined as follows.

$$\frac{\partial pf_l}{\partial p_m} = \frac{\partial pf_l}{\partial |v_i|} \times \frac{\partial |v_i|}{\partial p_m} + \frac{\partial pf_l}{\partial |v_j|} \times \frac{\partial |v_j|}{\partial p_m} + \frac{\partial pf_l}{\partial \theta_i} \times \frac{\partial \theta_i}{\partial p_m} + \frac{\partial pf_l}{\partial \theta_j} \times \frac{\partial \theta_j}{\partial p_m}$$

$$\frac{\partial qf_l}{\partial p_m} = \frac{\partial qf_l}{\partial |v_i|} \times \frac{\partial |v_i|}{\partial p_m} + \frac{\partial qf_l}{\partial |v_j|} \times \frac{\partial |v_j|}{\partial p_m} + \frac{\partial qf_l}{\partial \theta_i} \times \frac{\partial \theta_i}{\partial p_m} + \frac{\partial qf_l}{\partial \theta_j} \times \frac{\partial \theta_j}{\partial p_m}$$

$$\frac{\partial Pf_l}{\partial q_m} = \frac{\partial pf_l}{\partial |v_i|} \times \frac{\partial |v_i|}{\partial q_m} + \frac{\partial pf_l}{\partial |v_j|} \times \frac{\partial |v_j|}{\partial q_m} + \frac{\partial pf_l}{\partial \theta_i} \times \frac{\partial \theta_i}{\partial q_m} + \frac{\partial pf_l}{\partial \theta_j} \times \frac{\partial \theta_j}{\partial q_m}$$

$$\frac{\partial qf_l}{\partial q_m} = \frac{\partial qf_l}{\partial |v_i|} \times \frac{\partial |v_i|}{\partial q_m} + \frac{\partial qf_l}{\partial |v_j|} \times \frac{\partial |v_j|}{\partial q_m} + \frac{\partial qf_l}{\partial \theta_i} \times \frac{\partial \theta_i}{\partial q_m} + \frac{\partial qf_l}{\partial \theta_j} \times \frac{\partial \theta_j}{\partial q_m}$$

$$\frac{\partial pf_l}{\partial |v_i|} = |v_j| \times \left(G_{i,j} \times cos\theta_{i,j} + B_{i,j} \times sin\theta_{ij}\right) - 2 \times G_{i,j} \times |v_i|$$

$$\frac{\partial pf_l}{\partial |v_j|} = |v_i| \times \left(G_{i,j} \times cos\theta_{i,j} + B_{i,j} \times sin\theta_{i,j}\right)$$

$$\frac{\partial pf_l}{\partial |\theta_i|} = |v_i| \times |v_j| \times \left(-G_{i,j} \times sin\theta_{i,j} + B_{i,j} \times cos\theta_{i,j}\right)$$

$$\frac{\partial pf_l}{\partial |\theta_j|} = |v_i| \times |v_j| \times \left(G_{i,j} \times sin\theta_{i,j} - B_{i,j} \times cos\theta_{i,j}\right)$$

$$\frac{\partial qf_l}{\partial |v_i|} = |v_j| \times \left(G_{i,j} \times sin\theta_{i,j} - B_{i,j} \times con\theta_{i,j}\right) + 2 \times B_{i,j} \times |v_i|$$

$$\frac{\partial qf_l}{\partial |v_j|} = |v_i| \times \left(G_{i,j} \times sin\theta_{i,j} - B_{i,j} \times cos\theta_{i,j}\right)$$

$$\frac{\partial qf_l}{\partial |\theta_i|} = |v_i| \times |v_j| \times \left(G_{i,j} \times cos\theta_{i,j} + B_{i,j} \times sin\theta_{i,j}\right)$$

$$\frac{\partial qf_l}{\partial |\theta_j|} = |v_i| \times |v_j| \times \left(G_{i,j} \times cos\theta_{i,j} + B_{i,j} \times sin\theta_{i,j}\right)$$

Equation (4.9) represents apparent line flow sensitivity with respect to node injected active power matrix FSP of size L×(N-1)

$$FSP = \begin{bmatrix} fs_{1,2} & \cdots & fs_{1N} \\ \vdots & \ddots & \vdots \\ fs_{L,2} & \cdots & fs_{L,N} \end{bmatrix} \tag{4.9}$$

4.2 Negotiation process with network violation charge

4.2.1 P2P electricity market modeling

To represent a P2P electricity market operating in the absence of network violations, a constraint on the network state variable is added to the market model defined by equation (3.10) in chapter 3.2, which can be written as equation (4.10).

$$\max_{p_i, p_j}\left(\sum_{i}^{N_P} WP_i(p_i) + \sum_{j}^{N_C} WC_j(p_j)\right) \tag{4.10.a}$$

$subject\ to$

$$WP_i = \lambda_i \times p_i - C_i(p_i) - lp_i \times p_i \tag{4.10.b}$$

$$WC_j = \sum_{i \in N_P} \left[U(p_{j,i}) - \lambda_i \times p_{ji} - lp_j \times p_{j,i}\right] \tag{4.10.c}$$

$$p_i = \sum_{j \in N_C} p_{j,i}, \qquad \forall i \in N_P \tag{4.10.d}$$

$$p_n = \begin{cases} p_i - p_j, & i = j \\ p_n = p_i \ \ or \ \ p_n = -p_j, & i \neq j \end{cases} \tag{4.10.e}$$

$$\underline{p_i} \leq p_i \leq \overline{p_i}, \qquad \forall i \in N_P \tag{4.10.f}$$

$$\underline{p_j} \leq p_j \leq \overline{p_j}, \qquad \forall j \in N_C \tag{4.10.g}$$

$$|\underline{v}_n| \leq |v_n| \leq |\overline{v}_n|, \qquad \forall n \in N \tag{4.10.h}$$

$$\underline{sf_l} \leq sf_l \leq \overline{sf}_l, \qquad \forall l \in L \tag{4.10.i}$$

Equation (4.10.e) represents the relationship between the injected power p_n and the generation p_i of prosumer i and the consumption p_j of consumer j at a node in the distribution network where prosumer i and consumer j are located. P2P electricity trading leads to changes in the network state such as, voltage, and line flow. Equations (4.10.h) and (4.10.i) indicate that the node voltage and line flow resulting from the transaction should be remain within a certain reliable range.

4.2.2 Dual gradient ascent method

In a decentralized P2P electricity market mechanism, market must be cleared through information exchange between market participants without intervention of central authorities. In chapter 3, a market clearing algorithm using dual decomposition, a distributed optimization technique, is presented. However, this method requires that the constraints, including the objective function, can be decomposed into local problems. As equations (4.10.h) and (4.10.i) cannot be decomposed into local problems, the dual decomposition method is not applicable. Therefore, this study proposes a decentralized market clearing algorithm based on the dual gradient ascent method.

Equation (4.11) is an example optimization problem to illustrate the Dual gradient ascent method. The goal is to find values for x and z that maximize the objective functions: $\max_{x,z} (f(x) + g(z))$, subject to a constraint $Ax + Bz = c$.

$$\max_{x,z} (f(x) + g(z)) \tag{4.11.a}$$

$subject\ to$

$$Ax + Bz = c \tag{4.11.b}$$

$$L(x, z, u) = argmin f(x) + g(z) + u^T \times (Ax + Bz - c) \tag{4.12}$$

Equation (4.12) is the Lagrangian dual function for equation (4.11). If strong duality holds, the maximum value of the Lagrangian dual function coincides with the solution of the primal problem. The primal variables x and z are updated iteratively using the gradient ascent method. However, instead of simultaneous updating, the primal variables x and z are updated sequentially, with other variables utilizing the most recent values. The process is repeated until convergence is reached to obtain the solution to the given problem.

$$for\ k = 0,1,2,3, \ldots$$

$$x^{k+1} = \underset{x}{\operatorname{argmin}}\, L\left(x, z^k, u^k\right)$$

$$z^{k+1} = \underset{z}{\operatorname{argmin}}\, L\left(x^{k+1}, z, u^k\right)$$

$$\mathrm{u}^{k+1} = u^k - (Ax^{k+1} + Bz^{k+1} - c)$$

4.2.3 Dual gradient ascent method-based negotiation process

To establish the negotiation process for P2P electricity trading using the dual gradient ascent method, the Lagrange dual function of equation (4.10) is defined as equation (4.12).

$$
\begin{aligned}
&L\left(\lambda_i,\overline{\mu}_i,\underline{\mu_i},\overline{\nu}_j,\underline{\nu}_j,\overline{\xi}_l,\underline{\xi_l},\overline{\chi}_n,\underline{\chi_n}\right)\\
&=\min_{p_i,\,p_{ji}} L\left(\lambda_i,\overline{\mu}_i,\underline{\mu_i},\overline{\nu}_j,\underline{\nu}_j,\overline{\xi}_l,\underline{\xi_l},\overline{\chi}_n,\underline{\chi_n}\right)\\
&=\sum_j^{N_C}\sum_i^{N_P}\left(U\left(p_{j,i}\right)-lp_j\times p_{j,i}\right)-\sum_i^{N_P}\left(C_i(p_i)+lp_i\times p_i\right)\\
&+\sum_i^{N_P}\lambda_i\times\left(p_i-\sum_{j\in N_C}p_{j,i}\right)\\
&+\sum_i^{N_P}\overline{\mu}_i\times\left(\overline{p}_i-p_i\right)+\sum_i^{N_P}\underline{\mu_i}\times\left(p_i-\underline{p_i}\right)\\
&+\sum_j^{N_C}\overline{\nu}_j\times\left(\overline{p}_{\mathrm{j}}-\sum_{i\in N_P}p_{j,i}\right)+\sum_j^{N_C}\underline{\nu}_j\times\left(\sum_{i\in N_P}p_{j,i}-\underline{p}_j\right)\\
&+\sum_l^{L}\overline{\xi}_l\times\left(\overline{sf}_l-sf_l\right)+\sum_l^{\mathrm{L}}\underline{\xi_l}\times\left(sf_l-\underline{sf}\right)\\
&+\sum_n^{N}\overline{\chi}_n\times\left(|\overline{v}_n|-|v_n|\right)+\sum_n^{\mathrm{N}}\underline{\chi_n}\times\left(|v_n|-|\underline{v_n}|\right)
\end{aligned}
\tag{4.12}
$$

Where λ_i is the dual variable associated with equation (4.10.d) and represents the trading price of prosumer i, $\overline{\mu}_i$ and $\underline{\mu}_i$ are dual variables for equation (4.10.f) representing the maximum and minimum power generation limit of prosumer i, $\overline{\nu}_j$ and $\underline{\nu}_j$ are dual variables for equation (4.10.g) representing the upper and lower voltage limit at node j, $\overline{\xi}_l$ and $\underline{\xi}_l$ are dual variables for the network constraints of line flow in the distribution network caused by transactions of prosumers and consumers, and $\overline{\chi}_n$ and $\underline{\chi}_n$ are dual variables for the voltage limitation at a node in the network. To solve equation (4.12) using the dual gradient ascent method, values for the primal variables p_i and p_{ji} must be derived first. Prosumers and consumers must solve equations (4.13) and (4.14) during negotiation to determine their trading volume set points.

$$p_i^{k+1} = \underset{p_i}{argmin}\, L(p_i, p_{j,i}^k, lp_i^k, \lambda^k{}_i, \overline{\mu}_i^k, \underline{\mu}_i^k, \overline{\nu}_j^k, \underline{\nu}_j^k, \overline{\xi}_l^k, \underline{\xi}_l^k, \overline{\chi}_n^k, \underline{\chi}_n^k) \tag{4.13}$$

$$p_{ji}^{k+1} = \underset{p_{ji}}{argmin}\, L(p_i^k, p_{j,i}, lp_j^k, \lambda^k{}_i, \overline{\mu}_i^k, \underline{\mu}_i^k, \overline{\nu}_j^k, \underline{\nu}_j^k, \overline{\xi}_l^k, \underline{\xi}_l^k, \overline{\chi}_n^k, \underline{\chi}_n^k) \tag{4.14}$$

Under the Karush-Kuhn-Tucker (KKT) conditions, a stationarity condition for p_i and p_{ji} must be satisfied as in equations (4.15) and (4.16).

$$\nabla_{p_i} L(p_i, p_{j,i}^k, lp_i^k, \lambda^k{}_i, \overline{\mu}_i^k, \underline{\mu}_i^k, \overline{\nu}_j^k, \underline{\nu}_j^k, \overline{\xi}_l^k, \underline{\xi}_l^k, \overline{\chi}_n^k, \underline{\chi}_n^k) = 0 \tag{4.15}$$

$$\nabla_{p_{ji}} L(p_i^k, p_{j,i}, lp_j^k, \lambda^k{}_i, \overline{\mu}_i^k, \underline{\mu}_i^k, \overline{\nu}_j^k, \underline{\nu}_j^k, \overline{\xi}_l^k, \underline{\xi}_l^k, \overline{\chi}_n^k, \underline{\chi}_n^k) = 0 \tag{4.16}$$

which gives equations (4.17) and (4.18). Where $\frac{\partial sf_l}{\partial p_n}$ and $\frac{\partial |v_n|}{\partial p_n}$ represent the change in line flow and voltage magnitude at line *l* and node *n*, respectively, caused by the change in generation or consumption at a node *n* belonging to prosumer i and consumer j, as defined in Section 4.1. Therefore, as the transaction is repeated, the DSO determines the dual variables $(\overline{\xi}_l^k, \underline{\xi}_l^k, \overline{\chi}_n^k, \underline{\chi}_n^k)$ based on the magnitude of the network violation and distributes it to each participant according to network sensitivity.

$$p_i^{k+1} = \frac{\lambda^k - b_i - lp_i^k + (\underline{\mu}_i^k - \overline{u}_i^k) + \sum_l^L(\underline{\xi}_l^k - \overline{\xi}_l^k)\frac{\partial sf_l}{\partial p_n} + \sum_m^N(\underline{\chi}_m^k - \overline{\chi}_m^k)\frac{\partial |v_m|}{\partial p_n}}{2a_i} \quad (4.17)$$

$$p_{ji}^{k+1} = \frac{b_j - \lambda^k - lp_i^k + (\underline{v}_j^k - \overline{u}_j^k) + \sum_l^L(\underline{\xi}_l^k - \overline{\xi}_l^k)\frac{\partial sf_l}{\partial p_n} + \sum_m^N(\underline{\chi}_m^k - \overline{\chi}_m^k)\frac{\partial |v_m|}{\partial p_n}}{a_i} \quad (4.18)$$

When the values of p_i^{k+1} and $p_{j,i}^{k+1}$ are updated during the negotiation process, prosumers also update their corresponding Lagrange multiplier λ_i^{k+1} using equation (4.19) and passes it to the consumers for further negotiation. In other words, the difference between the trading volumes of the prosumer and the consumer leads to a change in the transaction price, and if there is no difference in their proposed volumes, the transaction price is determined and the negotiation process is terminated.

$$\lambda_i^{k+1} = [\lambda_i^k - k \times \nabla_{\lambda_i} L]^+ = \left[\lambda_i^k - k \times \left(p_i^k - \sum_{j \in N_C} p_{j,i}^k\right)\right]^+ \tag{4.19}$$

Equations (4.20), (4.21), (4.22), and (4.23) specify the rules for updating the dual variables $\overline{\mu}_i^k, \underline{\mu}_i^k, \overline{\nu}_j^k, \underline{\nu}_j^k$, which are associated with the minimum and maximum trading volume constraints of the prosumer and consumer as their trading volumes p_i^{k+1} and $p_{j,i}^{k+1}$ are updated. Thus, if the trading volume violates the minimum or maximum volume constraints, the update of dual variables serves to adjust the trading volume in a direction that reduces the constraint violation.

$$\overline{\mu}_i^{k+1} = \left[\overline{\mu}_i^k - k \times \nabla_{\overline{\mu}_i} L\right]^+ = \left[\underline{\mu}_i^k - k \times \left(p_i^k - \underline{p}_i\right)\right]^+ \tag{4.20}$$

$$\underline{\mu}_i^{k+1} = \left[\underline{\mu}_i^k - k \times \nabla_{\underline{\mu}_i} L\right]^+ = \left[\underline{\mu}_i^k - k \times (p_i^k - \underline{p}_i)\right]^+ \tag{4.21}$$

$$\overline{\nu}_j^{k+1} = \left[\overline{\nu}_j^k - k \times \nabla_{\overline{\nu}_j} L\right]^+ = \left[\overline{\nu}_j^k - k \times (\overline{p}_j - \sum_{i \in N_P} p_{j,i}^k)\right]^+ \tag{4.22}$$

$$\underline{\nu}_j^{k+1} = \left[\underline{\nu}_j^k - k \times \nabla_{\underline{\nu}_j} L\right]^+ = \left[\underline{\nu}_j^k - k \times (\sum_{i \in N_P} p_{j,i}^k - \underline{p}_j)\right]^+ \tag{4.23}$$

Equations (4.24), (4.25), (4.26), and (4.27) provide the rules for updating the dual variables $\overline{\xi}_l^k, \underline{\xi}_l^k, \overline{\chi}_n^k, \underline{\chi}_n^k$ which are associated with the constraints on line flow and node voltage limits, as the trading volumes p_i^{k+1} and $p_{j,i}^{k+1}$ are updated. The DSO calculates the apparent power flow on line l $\underline{sf_l}$ and voltage magnitude of node n $|\overline{v}_n|$ using the sensitivity factors as shown in equations (4.28) and (4.29). If the line flow and node voltage exceed their limit values, the dual variables are updated. These updated dual variables are then allocated to the prosumers and consumers based on the network sensitivity.

$$\overline{\xi}_l^{\,k+1} = \left[\overline{\xi}_l^{\,k} - k \times \nabla_{\overline{\xi}_l} L\right]^+ = \left[\overline{\xi}_l^{\,k} - k \times \left(sf_l^k - \overline{sf}_l\right)\right]^+ \tag{4.24}$$

$$\underline{\xi}_l^{\,k+1} = \left[\underline{\xi}_l^{\,k} - k \times \nabla_{\underline{\xi}_l} L\right]^+ = \left[\underline{\xi}_l^{\,k} - k \times \left(\underline{sf}_l - sf_l^k\right)\right]^+ \tag{4.25}$$

$$\overline{\chi}_n^{\,k+1} = \left[\overline{\chi}_n^{\,k} - k \times \nabla_{\overline{\chi}_n} L\right]^+ = \left[\overline{\chi}_n^{\,k} - k \times \left(|\overline{v}_n| - |v_n|^k\right)\right]^+ \tag{4.26}$$

$$\underline{\chi}_n^{\,k+1} = \left[\underline{\chi}_n^{\,k} - k \times \nabla_{\underline{\chi}_n} L\right]^+ = \left[\underline{\chi}^{k} - k \times \left(|v_n|^k - |\underline{v}_n|\right)\right]^+ \tag{4.27}$$

$$\begin{bmatrix} |sf_1| \\ . \\ . \\ . \\ |sf_l| \\ . \\ . \\ . \\ |sf_L| \end{bmatrix} = \begin{bmatrix} fs_{1,2} & \cdots & fs_{1,N} \\ \vdots & \ddots & \vdots \\ fs_{L,2} & \cdots & fs_{L,N} \end{bmatrix} \begin{bmatrix} p_2 \\ . \\ . \\ . \\ p_n \\ . \\ . \\ . \\ p_N \end{bmatrix} \tag{4.28}$$

$$\begin{bmatrix} |v_2| \\ . \\ . \\ . \\ |v_n| \\ . \\ . \\ . \\ |v_N| \end{bmatrix} = \begin{bmatrix} vs_{2,2} & \cdots & vs_{2,N} \\ \vdots & \ddots & \vdots \\ vs_{N,2} & \cdots & vs_{N,N} \end{bmatrix} \begin{bmatrix} p_2 \\ . \\ . \\ . \\ p_n \\ . \\ . \\ . \\ p_N \end{bmatrix} \tag{4.29}$$

$$\epsilon^k = \sqrt{\sum_i^{N_P} \left|p_i^{k+1} - p_i^k\right|^2} \tag{4.30}$$

The proposed negotiation process for P2P electricity trading with network violation management is summarized in Algorithm 4. During the process, prosumers and consumers carry out exchanging trading information simultaneously. Furthermore, electricity trading continues until prosumers and consumers reach a consensus on the transaction. The criterion for convergence is defined by equation (4.30), and the transaction continues until the value satisfies the convergence criterion.

Algorithm 4: P2P electricity trading negotiation process with network violation management by DSO using dual gradient ascent algorithm

Input: { $p_i^0, p_{ji}^0, \lambda^0{}_i, \overline{\mu}_i^0, \underline{\mu}_i^0, \overline{\nu}_j^0, \underline{\nu}_j^0, \overline{\xi}_l^0, \underline{\xi}_l^0, \overline{\chi}_n^0, \underline{\chi}_n^0$ }
Output: $\{p_i^*, p_{i,j}^*\}$

Repeat k = 1:max_iter

Consumer j:

Receive the trading price ($\lambda^k{}_i$) from prosumer $i \in N_P$

Calculate trading volume ($p_{j,i}^{k+1}$) using (4.19)

Update $\overline{\nu}_j^{k+1}, \underline{\nu}_j^{k+1}$ using (4.23) and (4.24)

Notify trading volume ($p_{j,i}^{k+1}$) to prosumer $i \in N_P$ and DSO

Prosumer i:

Receive the trading volume ($p_{j,i}^{k+1}$) from consumer $j \in N_C$

Calculate trading volume (p_i^{k+1}) using (4.18)

Update $\overline{\mu}_i^{k+1}, \underline{\mu}_i^{k+1}$ using (4.21) and (4.22)

Update and notify trading price ($\lambda^{k+1}{}_i$) using (4.20)

DSO:

Receive trading volume ($p_{j,i}^{k+1}$) from consumer $i \in N_P$

Estimate network state using (4.29) and (4.30)

Update penalties ($\overline{\xi}_l^{\,k+1}, \underline{\xi}_l^{\,k+1}, \overline{\chi}_n^{k+1}, \underline{\chi}_n^{k+1}$) using (4.25 to 4.28)

Allocate penalties to prosumers and consumer using (4.7) and (4.9)

until Convergence

Chapter 5 Case Study I

In this chapter, the effectiveness of network operation scheme with Causality-based system loss charge is investigated and verified with a decentralized trading mechanism.

5.1 Simulation settings

5.1.1 common configuration

Considering the distribution network where P2P electricity trading is expected to be implemented, the simulation utilizes the IEEE 33 nodes distribution network [49], as shown in Figure 7. The modified IEEE 33 node distribution network is used in this simulation, with a total of 7 prosumers and 16 consumers connected to each node of the network. The trading of electricity between prosumers and consumers is based on hourly delivery, with the unit of kWh. It is assumed that there are no power trading activities other than the power generation and consumption determined by the P2P electricity trading. Furthermore, the line parameters of the modified IEEE 33 node distribution network were set according to table 4.

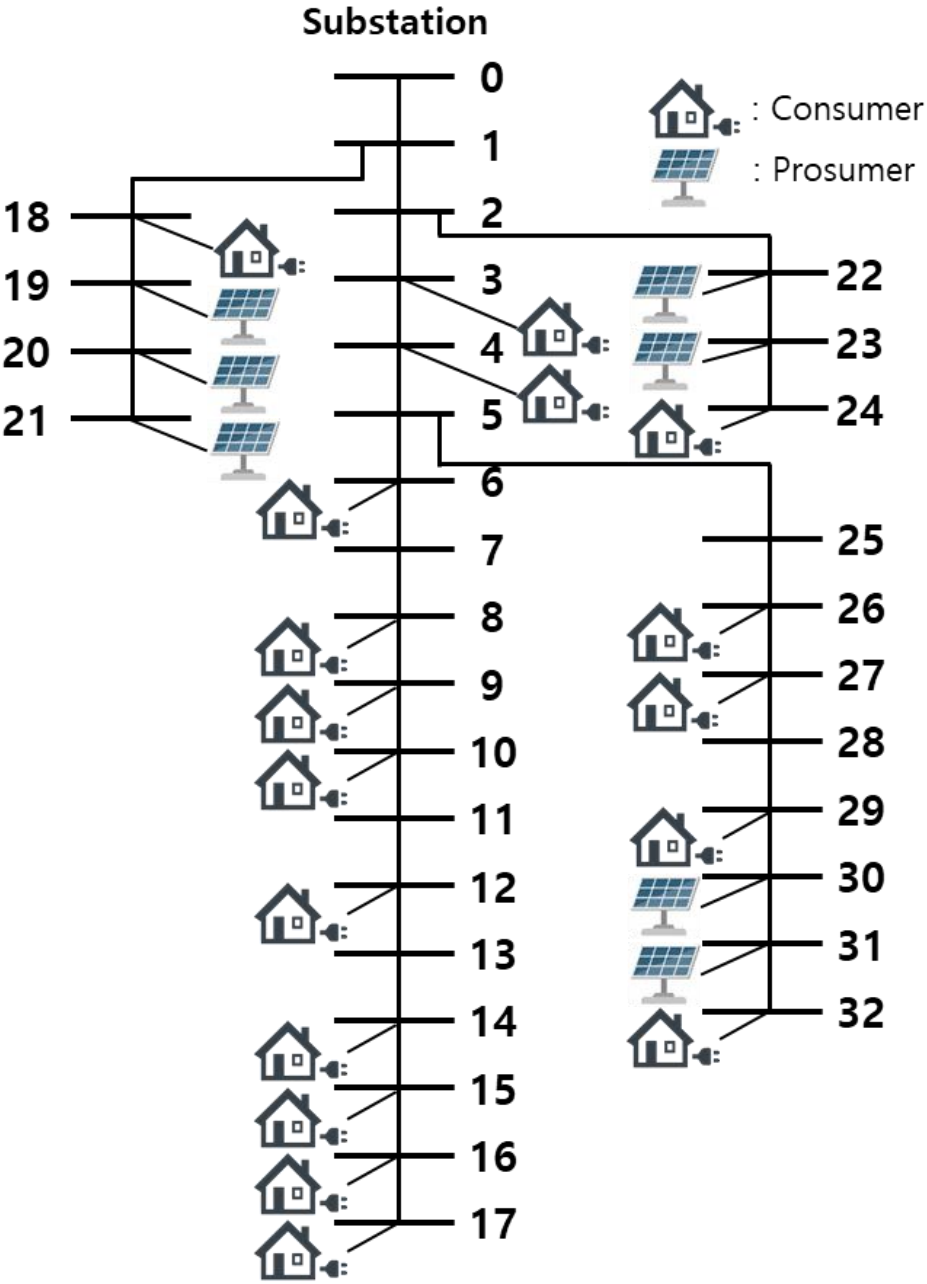

Figure 7 A modified IEEE 33-node distribution network with 17 consumers and 7 prosumers for peer-to-peer electricity trading.

Table 4 Line parameters for IEEE 33 nodes distribution network used in the simulation.

From bus	To bus	Line length [km]	Resistance/km [Ω/km]	Reactance/km [Ω/km]
0	1	1	0.0922	0.047
1	2	1	0.493	0.2511
2	3	1	0.366	0.1864
3	4	1	0.3811	0.1941
4	5	1	0.819	0.707
5	6	1	0.1872	0.6188
6	7	1	0.7114	0.2351
7	8	1	1.03	0.74
8	9	1	1.044	0.74
9	10	1	0.1966	0.065
10	11	1	0.3744	0.1238
11	12	1	1.468	1.155
12	13	1	0.5416	0.7129
13	14	1	0.591	0.526
14	15	1	0.7463	0.545
15	16	1	1.289	1.721
16	17	1	0.732	0.574
1	18	1	0.164	0.1565
18	19	1	1.5042	1.3554
19	20	1	0.4095	0.4784
20	21	1	0.7089	0.9373
2	22	1	0.4512	0.3083
22	23	1	0.898	0.7091
23	24	1	0.896	0.7011
5	25	1	0.203	0.1034
25	26	1	0.2842	0.1447
26	27	1	1.059	0.9337
27	28	1	0.8042	0.7006
28	29	1	0.5075	0.2585
29	30	1	0.9744	0.963
30	31	1	0.3105	0.3619
31	32	1	0.341	0.5302

In this simulation, the participating prosumers and consumers are defined based on the parameters presented in Table 5. The parameters $a_i, b_i,$ and c_i represent the quadratic coefficients, primary coefficients, and constants that define the power generation cost function of prosumer i. The variables $\underline{p_i}$ and $\overline{p_i}$ represent the constraints on the minimum and maximum power production limits of prosumer i, respectively. Similarly, the parameters $a_j, b_j,$ and c_j represent the utility function obtained by consumer j through purchasing electricity, with the variables $\underline{p_j}$ and $\overline{p_j}$ representing the minimum and maximum power purchase limits of consumer j, respectively.

The maximum values of prosumer's quadratic and primary coefficients are set to 0.015 $[¢/\text{kWh}^2]$ and 4.574 $[¢/\text{kWh}]$, respectively. The minimum values of consumer's quadratic and primary coefficients are set to 0.144 $[¢/\text{kWh}^2]$ and 20.5$[¢/\text{kW}]$, respectively, which are higher than all prosumers. This implies that the utility of the consumer is higher than the production cost of the prosumer, resulting in transactions always occurring.

Table 5 Parameters of prosumers and consumers for P2P electricity trading in IEEE 33 nodes distribution network for system loss charge simulation.

	Bus	a_i, α_j [¢/kWh^2]	b_i, β_j [¢/kWh]	c_i, γ_j [¢]	$\underline{p_i}, \underline{p_j}$ [kW]	$\overline{p_i}, \overline{p_j}$ [kW]
Prosumers (i)	19	0.0134	4.574	0	30	450
	20	0.0142	4.512	0	30	400
	21	0.0136	4.446	0	20	350
	22	0.015	4.548	0	30	400
	23	0.0146	4.516	0	30	400
	30	0.0144	4.574	0	35	450
	31	0.0138	4.498	0	25	350
Consumers (j)	3	0.124	20.5	0	30	160
	4	0.112	19.8	0	25	170
	6	0.108	19.3	0	45	175
	8	0.092	19.4	0	30	210
	9	0.09	19.5	0	40	210
	10	0.114	20.1	0	35	170
	12	0.1	19	0	30	190
	14	0.126	19.2	0	30	150
	15	0.128	19.4	0	25	150
	16	0.124	19.8	0	45	150
	17	0.114	19.9	0	30	170
	18	0.1	19.2	0	30	180
	24	0.126	19.6	0	30	150
	26	0.122	19.4	0	30	150
	27	0.144	20	0	30	130
	29	0.114	19.5	0	30	170
	32	0.11	18.7	0	25	170

5.1.2 simulation scenarios

Table 6 shows the summary of scenarios. a unit system loss price needs to be established in order to calculate the system loss cost. The unit system loss price represents the power that the DSO procures from the transmission system to compensate for system losses that occur in the distribution system due to P2P transactions. In order for prosumers and consumers to participate in P2P electricity trading, the transaction price should be established between the wholesale price in the transmission market and the retail price to the utility. This is because prosumers need to sell electricity at a price higher than the wholesale price, while consumers need to purchase electricity at a price lower than the retail price in order to achieve economic benefits. For this study, considering an average P2P electricity transaction price of 16 ¢/kWh in the simulation, the unit system loss price is set to 10 ¢/kWh. Thus, this means that the DSO pays 10 ¢/kWh to purchase electricity from the transmission network to compensate for system losses caused by the P2P transactions, and distributes the cost to P2P electricity market participants using the proposed loss allocation schemes. In A1, the system loss cost is equally distributed among all market participants. In A2 and A3, the cost is distributed among market participants using incremental transmission loss coefficients and Shapley values, respectively.

Table 6 Configuration of the scenario in the simulations for the system loss charging schemes. ($\phi_{m,n}$: Causal relationship factor for system losses determined by incremental transmission loss, $\phi_{s,n}$: Causal relationship factor for system losses determined by shapely value)

Scenario	Loss allocation schemes	The unit system loss price	Loss allocation prices
A1	Equal loss allocation		$\frac{\Lambda \times \text{System losses}}{Total\ trading\ volume}$
A2	Marginal loss allocation	Λ [¢/kWh] (ex, 10)	$\frac{\Lambda \times \text{System losses} \times \varphi_{m,n}}{Total\ trading\ volume}$
A3	Shapely value-based loss allocation		$\frac{\Lambda \times \text{System losses} \times \varphi_{s,n}}{Total\ trading\ volume}$

5.2 Simulation results

Figure 8 illustrates the results of the system losses incurred as a result of the transactions in each scenario. In A2 and A3, the system losses are almost the same, at 109.230 kWh and 109.410 kWh, respectively, while in A1, the system losses amount to 116.672 kWh. On average, the losses incurred in A2 and A3 are 6.302% lower than the losses incurred in A1. In A1, the loss cost is ¢ 1166.718, whereas in A2 and A3, the loss costs are ¢ 1092.289 and ¢ 1094.107, respectively. It can be observed that the loss costs in A1 are about 6% higher than the loss costs in A2 and A3. In other words, the application of loss management schemes based on the cost-causality-based principle reduces system losses and loss costs in the P2P electricity market in A2 and A3.

In A2 and A3, a decrease in system loss can be observed as a result of trading, however, there are no significant changes in trading volume. Figure 9 illustrates the total trading volume and market welfare resulting from trading in each scenario. Market welfare is calculated as the sum of net benefit (revenue - generation cost - loss cost) obtained by the prosumer and welfare (utility - payments - loss cost) obtained by the consumer. In A1, A2, and A3, the trading volume remained almost unchanged at around 2,705 kWh. However, the total market welfare generated in A1 is ¢ 21,188, while in both A2 and A3, the market welfare slightly increased to ¢ 21,185. This implies that the change in system loss and market welfare, with trading volume remaining nearly constant in all scenarios, indicates a change in trading patterns among market participants.

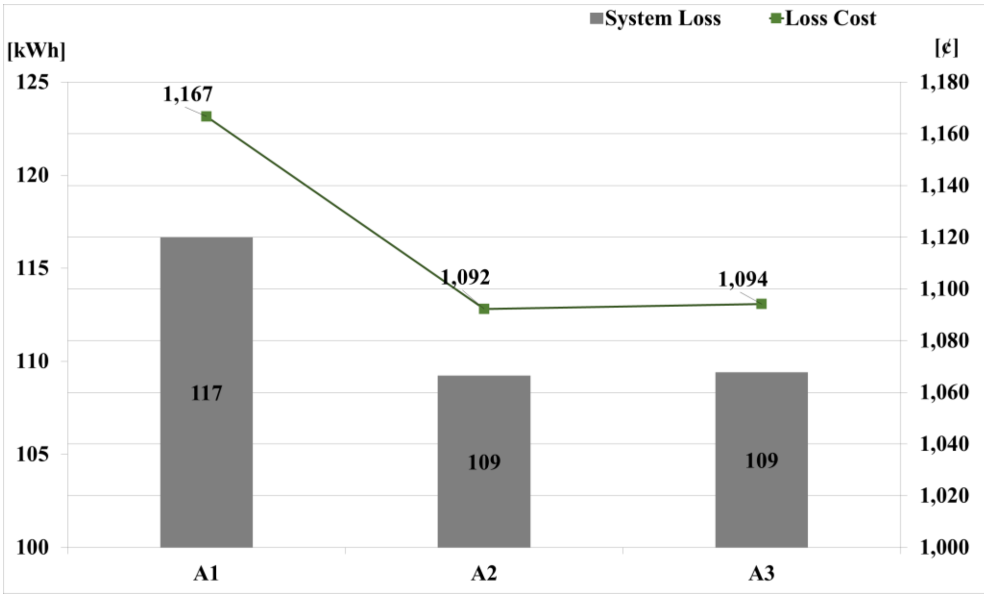

Figure 8 Amount of system losses and loss costs corresponding to trading results of each scenario.

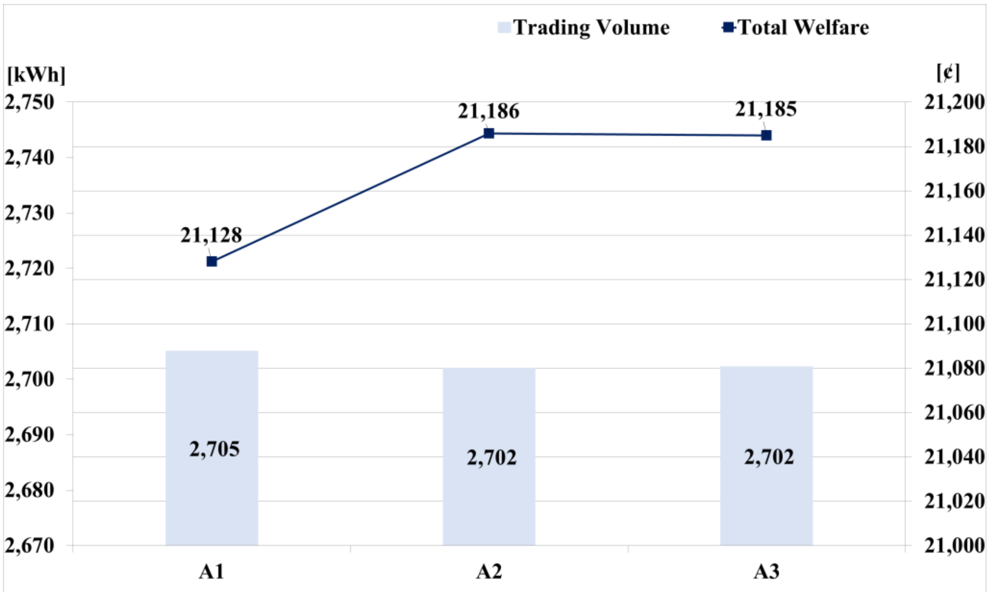

Figure 9 Total market welfare and trading volume for each scenario.

(the total sum of market participants' utility obtained from the transaction)

As shown in Figure 10, In comparison to A1, the changes in trading volume for market participants are as follows in A2 and A3. In A2, the producer located at node 19 has a decrease in trading volume of 4.55 kWh, while the producer located at node 30 has an increase in trading volume of 1.927 kWh. Consumers located at nodes 6, 18, 29, and 32 has an increase in total trading volume of 54.423 kWh. However, consumers at nodes 9, 12, 14, and 15 have a decrease in trading volume of more than 447.854 kWh. Similar patterns are observed in A3. The producer at node 19 has a decrease in trading volume of 4.638 kWh, while the producer at node 30 has an increase in trading volume of 2.229 kWh. Consumers located at nodes 6, 18, 29, and 32 have an overall increase in trading volume of 50.748 kWh. However, consumers at nodes 9, 12, 14, and 15 have a decrease in total trading volume of 53.777 kWh.

The reason for this change can be observed in Figure 11, where prosumers at nodes 19, 20, and 21 have a positive loss price, indicating that they contribute to the overall system loss as they generate more power. Conversely, prosumers at nodes 22, 23, 30, and 31 are charged a very small price, even a negative price, indicating that they contribute to reducing system losses as they generate additional power. It is noting that nodes 22, 30, and 31 contribute to reducing system losses. As a result, prosumers at nodes 22, 30, and 31 trade electricity at a lower price in A2 and A3 compared to A1, reflecting the negative loss price in the transaction price. Additionally, consumers located from Node 9 to node 17 have a decrease in trading volume in all scenarios due to the imposition of high transmission loss charges.

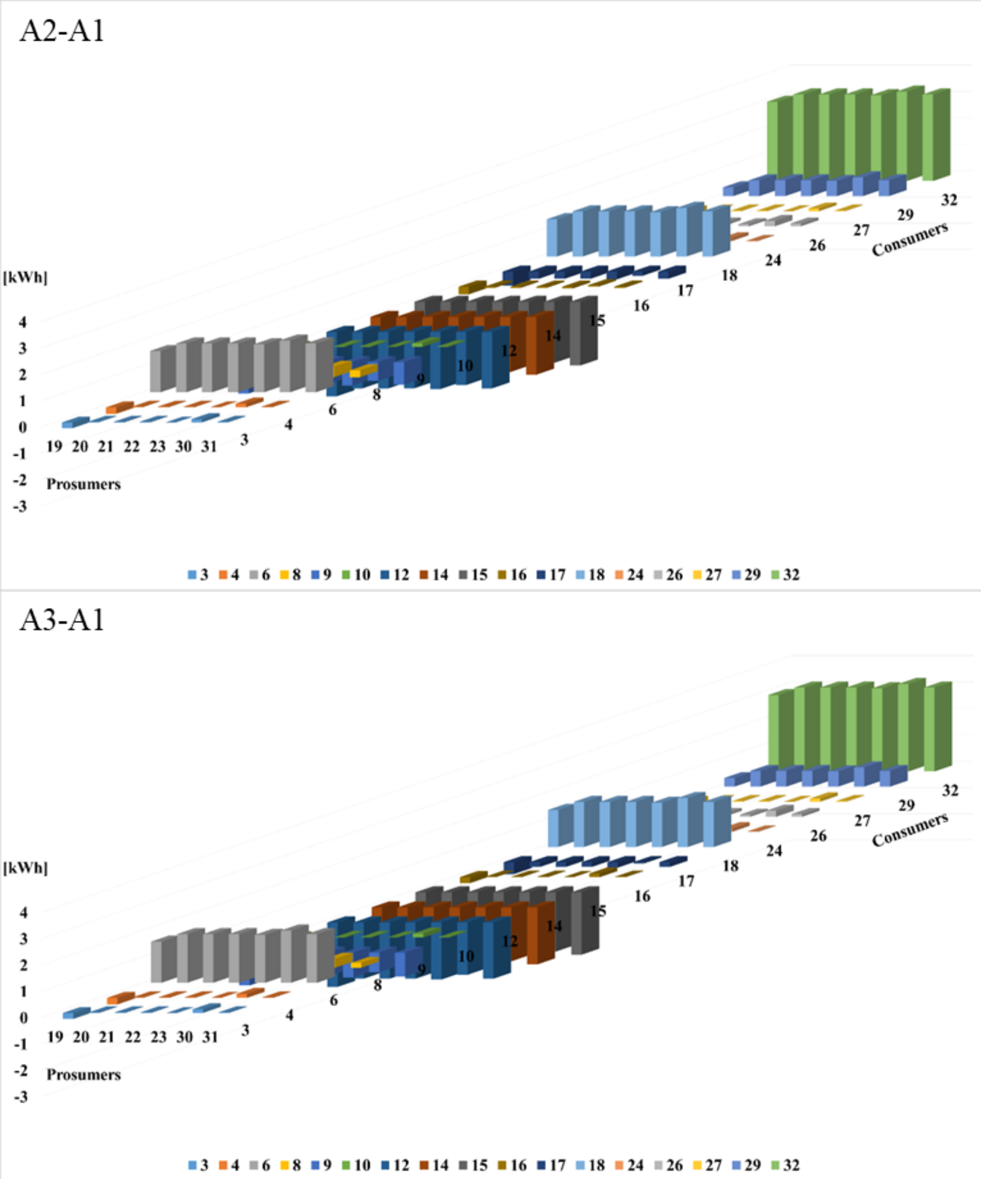

Figure 10 Change in trading volume of market participants in each scenario.

(A2-A1: Changes in trading volume at A2 based on A1, A3-A1: Changes in trading volume at A3 based on A1)

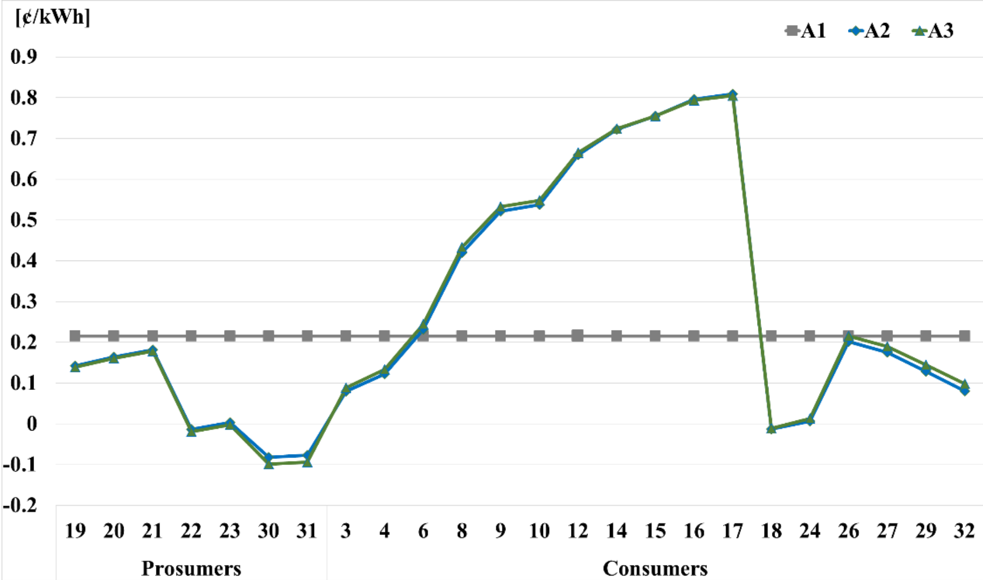

Figure 11 Unit loss charge assigned to prosumers and consumers for each scenario.

Since P2P electricity trading has not yet been applied in practice, it is possible to exactly determine the unit system loss price to compensate for system losses. Therefore, an analysis to examine the effects of different unit system loss prices on the results of P2P electricity trading is performed. Figure 12 shows that the change in trading volume in A2 and A3 compared to A1 is not significant, ranging from 0.3% to 0.5% increase. The increase in trading volume may not have a significant impact on improving losses and increasing market welfare. It is also mentioned that as the unit system loss price increases, the trading volume decreases due to the increased system loss cost to be paid by market participants. However, without specific values for trading volume, unit system loss prices, and their impact on market welfare, it is challenging to make definitive conclusions about the significance of the changes in trading volume on system losses and market welfare. Further analysis and data may be needed to accurately assess the impact of trading volume on the outcomes of the case study.

Figure 13 presents the changes in system losses for each scenario as the unit system loss price varies. In all scenarios, it is evident that system losses are reduced to a greater extent in A2 and A3 compared to A1. Furthermore, the reduction in system losses becomes more significant as the unit system loss price increases. For instance, when the unit system loss price is set at ¢7, the average decrease in system losses is 4.503% in A2 and A3 compared to A1. However, when the unit system loss price is increased to ¢16, the reduction in system losses reaches 11.442%. This suggests that as the unit system loss price increases, the allocation of losses also increases, which has a greater impact on the overall utility that market participants can obtain through power trading. The linear relationship between the unit system loss price and the reduction in system losses is clearly observed in the results, indicating that the unit system loss price is an important factor to consider in the design and implementation of P2P electricity trading mechanisms.

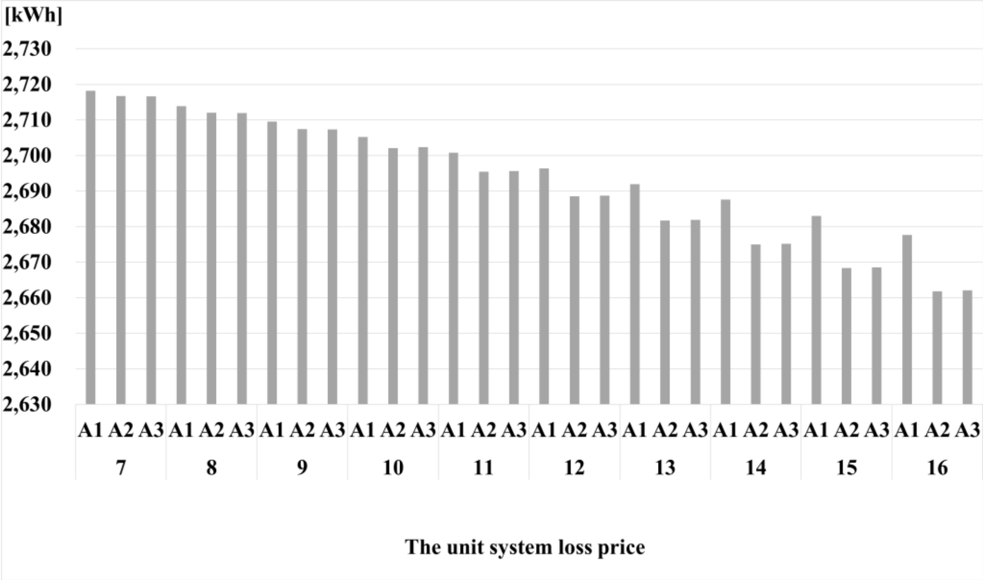

Figure 12 Comparison of trading volume for each scenario according to the change in unit system loss price.

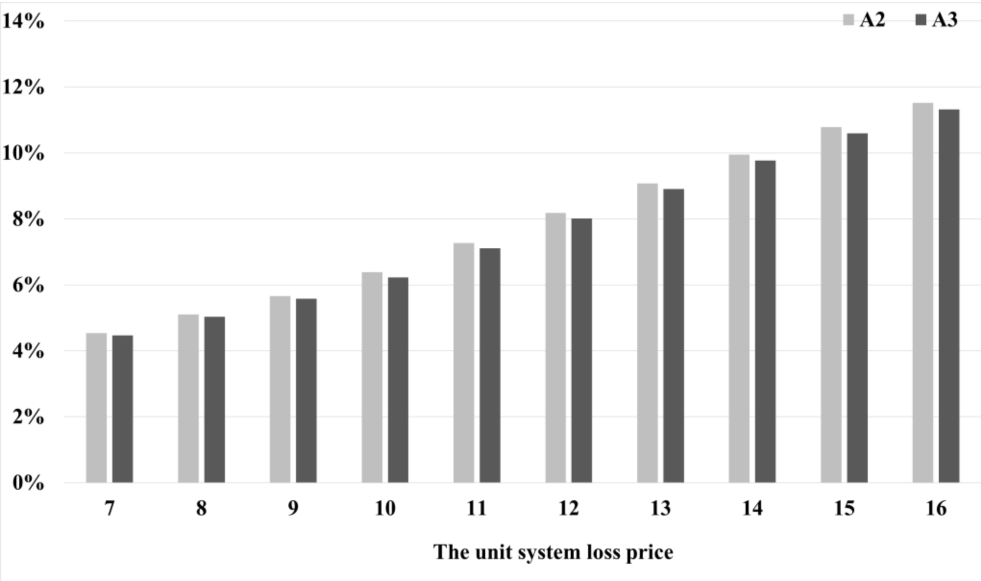

Figure 13 System loss reduction comparing to A1 by the unit system loss price.

Chapter 6 Case Study II

In this chapter, the effectiveness of the network operation scheme with causality-based violation charge is verified through simulations.

6.1 Simulation settings

6.1.1 Common configuration

The physical environment in which P2P electricity trading is conducted are same as modified IEEE 33-node distribution system same as in chapter 5. The characteristic parameters used to determine market participants' transactions are also taken from Table 5, which was used for the system loss charge. To validate the network operation scheme with causality-based violation charge in the presence of system constraints, the capacity of all lines has been set to 1,000 kVA, and the operational limits for node voltage have been set from 1.01 p.u. to 0.95 p.u.

6.1.2 simulation scenarios

Five scenarios are set up as shown in table 7. B1 represents the case where transactions are performed without any network operation scheme. B2 and B3 are established in this study to verify that the proposed method is more cost-effective. B2 uses the power flow equation to accurately estimate the network state and imposes a fixed violation charge when a network violation occurs. In B3, the sensitivity factor-based network operation scheme proposed in this dissertation is used to estimate the line flow and congestion, and the penalty is also allocated using sensitivity factor. B4 and B5 are set up in this study to demonstrate that the proposed method is more suitable for managing line congestion. In B4, transaction information and PTDF are used to estimate the flow on a line in the network and allocate violation charge when line congestion occurs. B5 uses sensitivity factor to calculate line congestions and allocate violation charge using the sensitivity factor.

Table 7 Configuration of the scenarios in the simulations for the network operation schemes using violation charge.

Scenario		Network Operation Scheme	
		Network state calculation methods	Violation charge allocation methods
B1		No method	No Charge
Cost Efficiency	B2	Power flow equations	Fixed violation charges for voltage violation
	B3	Sensitivity factors	Allocating voltage violation charge based on sensitivity factor
Congestion Management	B4	PTDF	Allocating violation charges based on PTDF only for line congestions
	B5	Sensitivity factors	Fixed violation charges for line congestions

6.2 Simulation Results

6.2.1 Simulation result for cost efficiency

Figure 14 illustrates the node voltage profiles of P2P electricity trading in scenarios B1 B2 and B3. In B2 and B3, it is evident that the node voltage profiles lie within the reliable voltage level range. In B3, node 17 and 21, which are vulnerable to voltage violation, and its adjacent nodes exhibit voltage profiles that are close to the limit voltage. However, in B2, a more reliable voltage profile is observed on these nodes, which attributed to the decrease in overall transaction volume. Table 10 presents the total market welfare and trading volume stemming from P2P electricity trading in B2 and B3. The trading volume in B2 surpasses that of B3 by over 51%, and the total market welfare is over 20% higher, indicating that the violation charge based on the cost-causality principle promotes greater market efficiency.

Table 8 Comparison of market results between B2 and B3 in terms of trading volume and market welfare

scenario	Trading volume [kWh]	Market welfare [¢]
B2	1,429	16,447
B3	2,162	19,769
Rate of increase	51.243%	20.198%

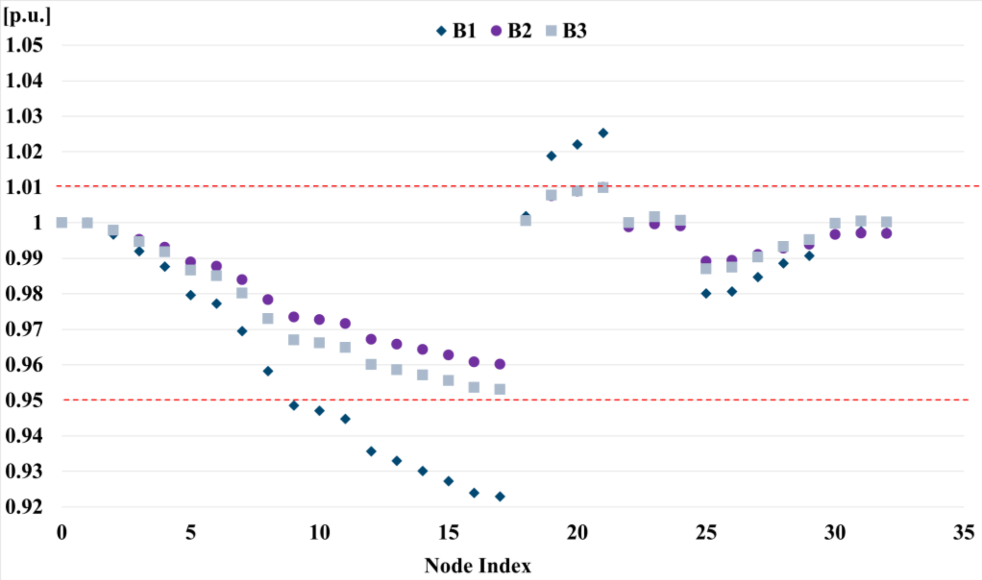

Figure 14 The voltage at nodes of the distribution network according to the market results in B1, B2 and B3.

Under the management scheme of B2, the DSO set a fixed charge of approximately ¢4/kWh to all market participants for voltage violation at node 21 as shown in figure 15. As shown in figure 16, the DSO imposes large violation charge on prosumers located at nodes 19, 20, and 21 to curb the generation at node 21 and avoid a voltage violation. Conversely, no charges are imposed on prosumers located at nodes 22, 23, 30, and 31, which have less direct association with node 21. Furthermore, consumers located at nodes 12, 14, 15, 16, and 17, which are in close proximity to node 17 and prone to voltage drops, incurred higher penalties than other consumers, which contributed to limiting transaction volume. In contrast, Consequently, both prosumers and consumers who have a minimal impact on causing voltage violations would encounter a decrease in trading volume.

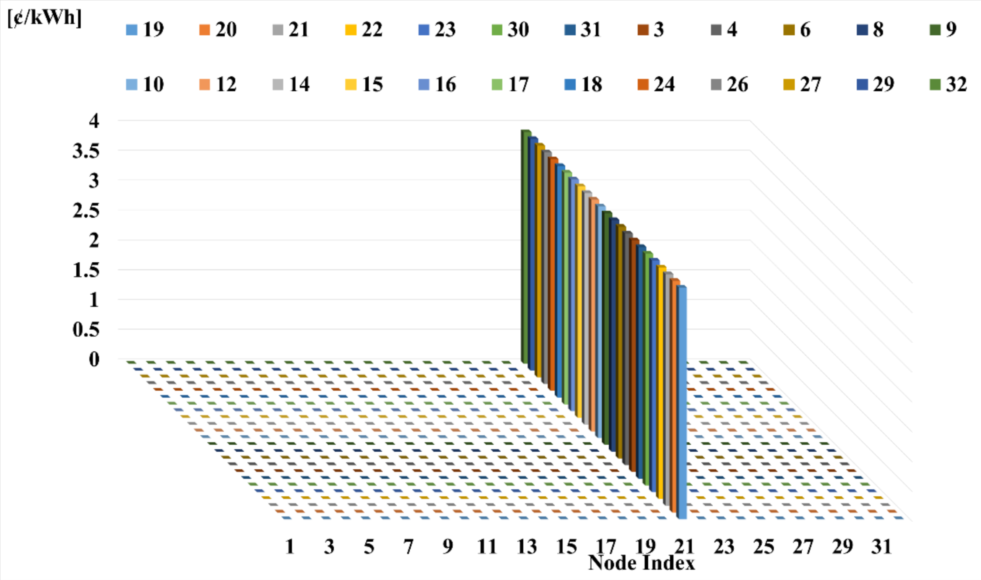

Figure 15 Voltage violation charge assigned to prosumers and consumers in B2.

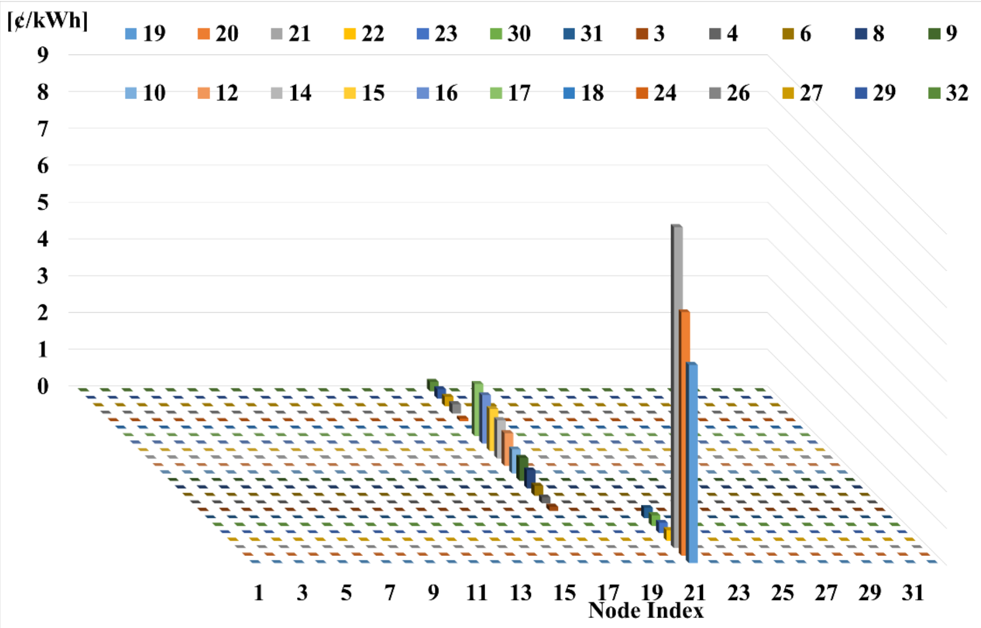

Figure 16 Voltage violation charge assigned to prosumers and consumers in B3.

Figures 17 and 18 depict the change in transaction volume of individual prosumers and consumers for each scenario. In B2, the transaction volume of prosumers at all nodes consistently decreased to approximately 200 kWh, and the trading volume of all consumers also reduced compared to B1. Conversely, in B3, the trading volume of prosumers at nodes 19, 20, and 21 is reduced by around 50% compared to the B1 scenario, while the trading volume of consumers located at nodes 12, 10, 14, 15, 16, and 17 is decreased by an average of 35%.

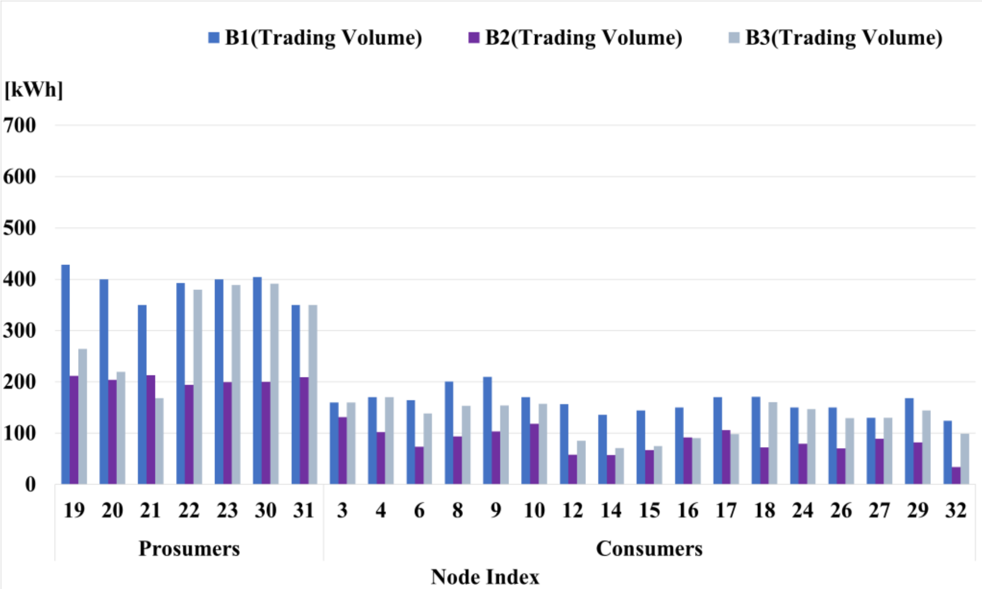

Figure 17 Comparison of the trading volume of prosumers in B1, B2 and B3.

6.2.2 Simulation results for congestion management

The simulation results of the line flow occurred by trading results are shown in Figure 18. With a flow limit of 1,000 kVA or 1,000 kW for all lines, line congestion occurred on both B1 and B4. In B1, where no network violation charge is applied, line congestion occurred due to P2P electricity trading on lines 1, 2, 3, 4, 5, 6, 7, 8, 17 and 18. However, in B2, where PTDF is used to manage line congestion, line congestion occurred on line 2 and 5 due to an active line flow of 1,056 kW and 1,025 kW. In B3, a line flow of 958 kVA and 974 kVA are observed on line 2 and 5 as a result of P2P electricity trading. This flow is lower than the flow limit, indicating the effectiveness of the network violation charge using sensitivity factor to manage line congestion.

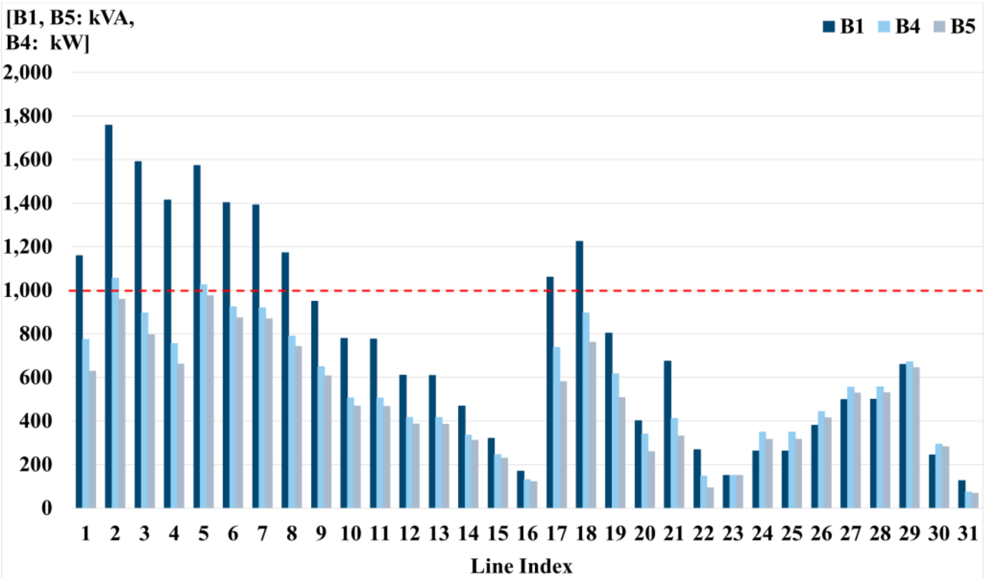

Figure 18 Line flows in the distribution network according to the market results in each scenario.

The network operation with violation charge works by restricting the trading volumes of prosumers and consumers. Figure 19 and Figure 20 show the trading volumes of prosumers and consumers in each scenario. In B1, all prosumers have higher or equal trading volumes compared to other scenarios, and the trading volume of nodes 19, 20 and 21, which affect the flow on line 2, 3, 4, 5, 6, and 7 where line congestion occurs, is more than 130 kW higher than other nodes. In B4, the trading volume is lower than in B1, and the decrease in trading volume at nodes 19, 20, 21, 22 and 23 leads to a decrease in the flow on line 2. In the meanwhile, the trading volume of prosumers located at node 30 and 31 are not decreased. The trading volume of consumers located at nodes 4, 6, 8, 9, 10, 12, 15, 16, and 17, which impact Lines 2, 3, 4, 5, 6, and 7, also decreased. The same phenomenon occurred in B5 as well. The trading volume of prosumers located at nodes 19, 20, 21, 22, and 23 decreased, and the trading volume of consumers located at nodes 4, 6, 8, 9, 10, 12, 15, 16, and 17 also decreased. Furthermore, the trading volume decreased even more in B5 compared to B4, resulting in the absence of line congestions in B5.

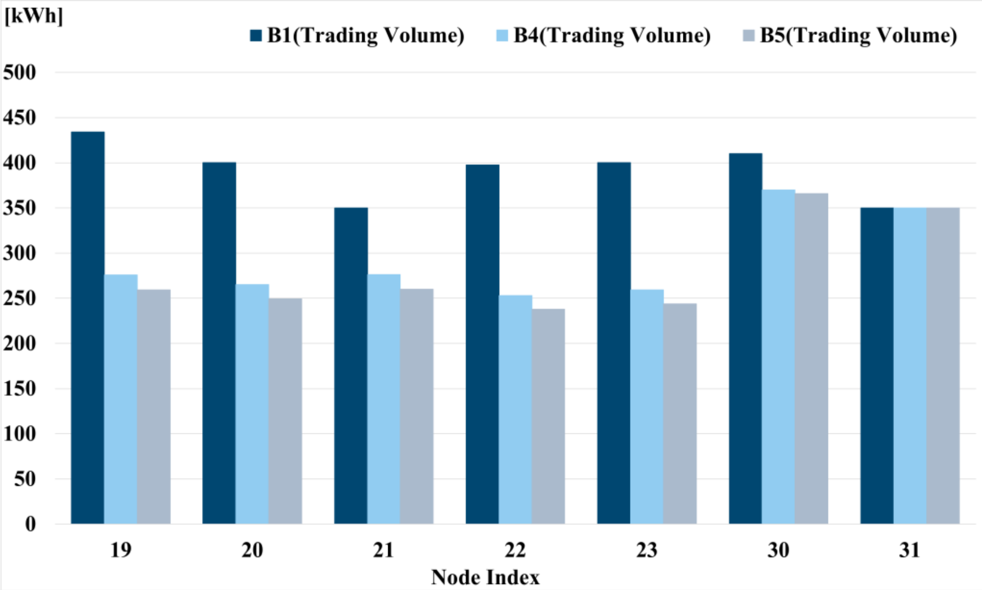

Figure 19 Comparison of the trading volume of prosumers for each scenario.

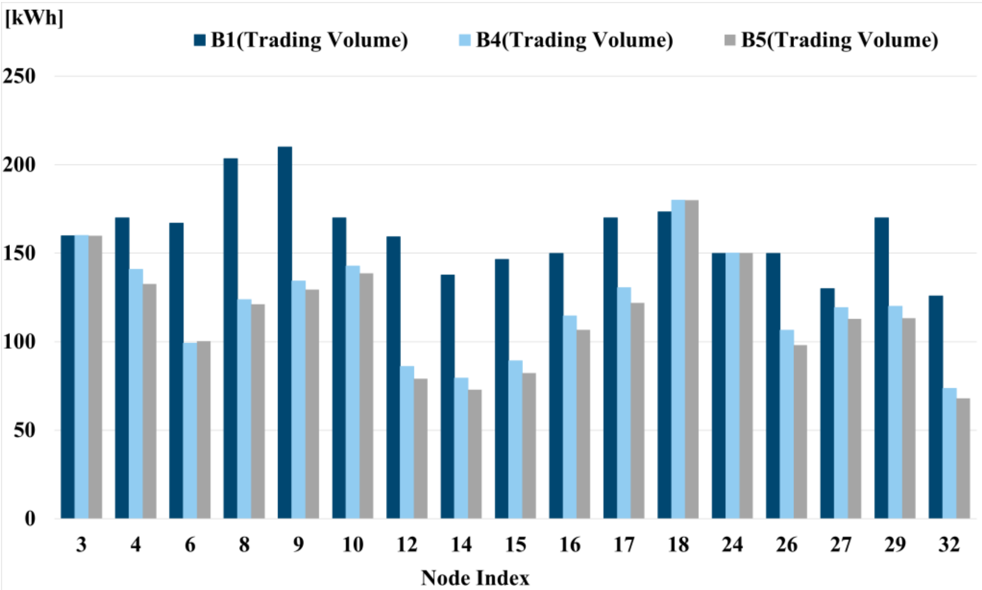

Figure 20 Comparison of the trading volume of consumers for each scenario.

The network operation with violation charge run by estimating the impact of transaction volumes of prosumers and consumers on network violations, imposing violation charge, and distributing them based on the cost-causality principle. Figure 21 illustrates the charge for line congestion in B2 and B3. Notably, prosumers 19, 20, 21, 22, and 23 receive high violation charge as their transactions directly influence the line flow on line 2 and 5, while prosumers 30 and 31 are subject to low violation charge as their impact on the line flow is small. Similarly, consumers other than those located at nodes 18 and 24 are assigned high violation charge since their transaction volume increases the flow on line 2. Consequently, the imposed violation charge makes an increase in the transaction volumes of prosumers at nodes 30 and 31 in B2 and B3, while reducing the trading volume of other prosumers. Furthermore, the transaction volumes of consumers 18 and 24 decrease as a result of the violation charge.

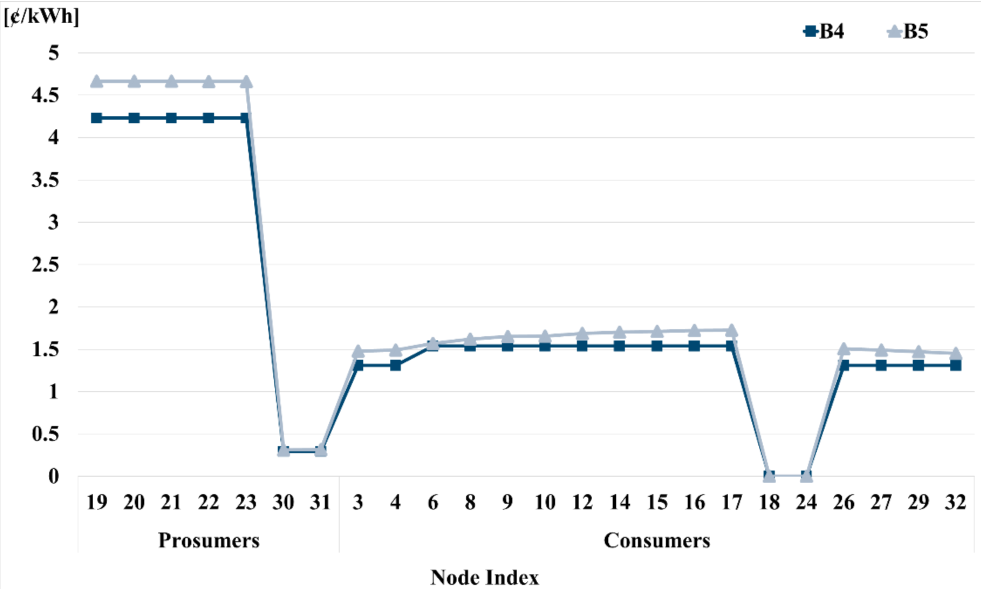

Figure 21 Violation charge for line congestion assigned to prosumers and consumers in B2 and B3.

Both B4 and B5 has distributed violation charge based on the cost-causality principle for line congestion, but line congestion occurs in B4. This is due to a low calculation accuracy of PTDF. PTDF represents the change in line flow with respect to the injected active power of a node. However, to derive it, it ignores the resistance, which is an assumption made for performing the decoupled power flow equation, and does not consider voltage changes, making it unsuitable for distribution networks with high resistance and large voltage variations. Figure 22 shows the error between the line flow estimated by PTDF, sensitivity factor in B4 and B5 and the actual line flow. On average, PTDF showed an error of 1.9%, while sensitivity factor showed an error of about 1%. It can be seen that this error is particularly significant on the line adjacent to the line where the reverse current occurs.

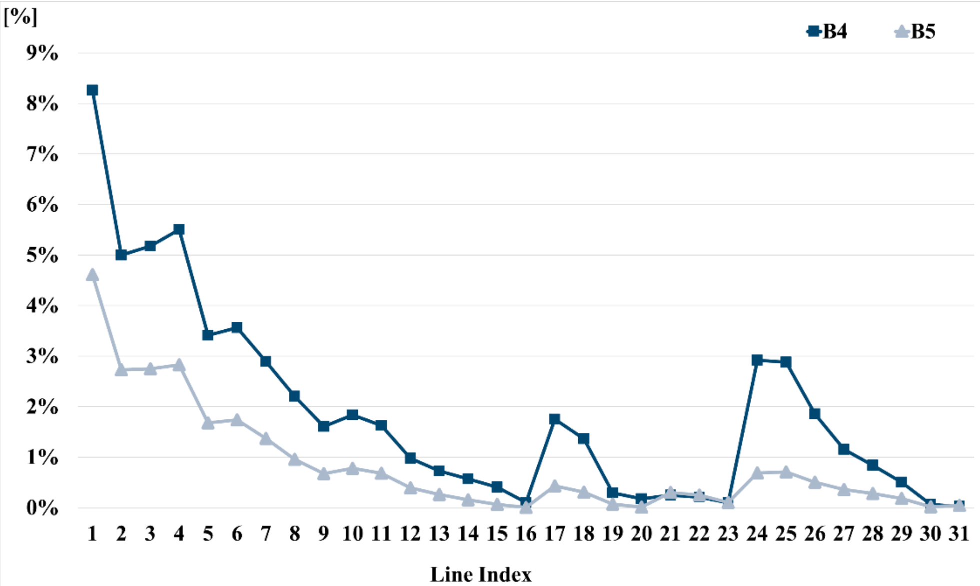

Figure 22 The errors between line flows calculated by the power flow equation and estimated line flows calculated by PTDF and sensitivity factors in B2 and B3.

Chapter 7 Conclusions and Future Works

7.1 Conclusions

The P2P electricity market operated by a decentralized mechanism, market participants carry out transactions solely for their own benefit, without taking responsibility or playing a role in the management of the system losses and network violations, leading to reduced cost-efficiency and system failures and accidents. To address these issues, several previous studies have suggested methods for network operation. However, these methods could not proactively encourage the cooperation of market participants. Against this backdrop, this study proposes a network operation scheme for DSOs to enhance cost-efficiency and ensure network reliability with P2P electricity trading by a decentralized mechanism.

The proposed DSO operation scheme aims to encourage market participants to cooperate in operating the network by allocating network service charge to be paid by the participants. Specifically, the DSO informs market participants of the system loss charge to reduce system losses and improve market efficiency. The study uses the cost-causality principle to allocate the system loss charge. This principle implies that market participants should pay the system loss charge to the extent that they contributed to the system loss. The study finds that the casualty-based system loss charge is superior to postage stamp method in terms of the optimal market outcome. Assuming that market participants' utilities strictly convex and their contributions to system losses can be distinguished based on their trading volume, the study demonstrates that the conditions for satisfying the Nash equilibrium of market participants and the first-order conditions for the optimal market are equivalent. In order to design causality-based system loss charge, the study proposes a marginal loss allocation using sensitivity to system losses against to trading volume, and a Shapely value loss allocation, which represents the average marginal contribution to system losses.

The decentralized P2P electricity trading process with system loss charge is proposed. It is formulated as an optimization problem, and the gradient ascent method and dual decomposition method are utilized to solve the optimization problem in a decentralized manner through information exchange among market participants. Specifically, a Lagrange dual problem is derived from the primal problem, and is partitioned into local problems for each market participant. Each participant solves its local problem to maximize its own utility and shares the result with counterparties. Counterparties use this information to solve their own local problems and maximize their own utility, and transmit the results back to the counterparties. This iterative process continues until a converged transaction result is obtained. During this process, the DSO acquires the trading volume transmitted by market participants and estimates the system losses through it. The allocated system loss charges are transmitted to market participants using marginal loss allocation prices or shapely value. In other words, market participants receive information about the system losses generated by their transactions in the form of prices and can take them into account when making transactions.

The decentralized P2P electricity trading process with network operation using violation charge is proposed. The sensitivity factors are used to formulate the P2P electricity trading that ensures that the market outcome is within the range of reliable operation. Constraints for line congestion and voltage violations are added to the optimization problem to define the market model. The primal problem was converted into a Lagrange dual problem using the gradient ascent method and stationary condition. The trading process was designed to solve the problem with only the information exchange of market participants. Each market participant establishes its optimal trading volume by solving a local problem set as the first-order condition of the Lagrange dual problem. The optimal trading volume is transmitted to the counterparties, and they establish their own optimal trading volume by solving their local problem in consideration of the other party's optimal trading volume. This process continues until converged trading results are obtained. The DSO checks for network violations by obtaining transaction volume information from market participants. If a violation occurs, violation charge is allocated using sensitivity factors and delivered to the market participant. Market participants establish optimal trading strategies in consideration of the allocated violation charge. Thus, those with a large violation charge reduce their trading volume to avoid a decline in profits or utility, leading to the suppression of network violations.

To validate the effectiveness of the proposed network operation scheme with the network service charge, a case study was conducted using a modified IEEE 33 distribution network. Firstly, the findings indicate that operation scheme led to a reduction in system losses compared to the postage-stamp method, without any changes in the total trading volume. In other words, the change in system losses resulted from alterations in the trading volume of each market participant. In the trading environment where the system loss charge is allocated by cost-causality, market participants located in nodes with higher system loss charge decide to reduce trading, whereas market participants in nodes with lower system loss charge an increase in trading volume, when comparing to the network operation using postage-stamp method. Hence, the proposed scheme can have the effect of reducing trading volume as the contribution to the losses increases. Also, it is observed that the marginal loss method and the shapely value method exhibits almost the same system loss charge for each node.

Secondly, the network operation scheme with violation charge shows cost-effective results with the P2P electricity trading. the causality-based violation charge demonstrates superior performance in terms of pursuing social-welfare compared to the fixed violation charge, which imposes excessive violation charge on the market participant who do not have little impact on violations, thereby reducing the incentive for trading. Further, by using sensitivity to estimate line flows, the error rate is reduced by approximately 50% compared to the line flow estimation obtained using PTDF. Particularly, the error rate of line flow increases on the line with reverse flow and its neighboring lines, making it difficult to manage line congestion accurately using PTDF. However, the sensitivity factor used in this study enables precise estimation and management of line congestion. Moreover, by estimating the node voltage through sensitivity factors without solving the power flow equation, providing a computational efficiency as the number of market participants increases.

The significance of this dissertation lies in proposing the network operation scheme for P2P electricity trading using network charge to improve cost-efficiency while enhancing network reliability. The following contributions can be summarized: First, it demonstrated that the system loss charge based on the cost-causality principle is consistent with the optimal market efficiency. Two methods are used for setting the system loss charge, they did not show significant differences in market results. Therefore, the contribution to system losses depends on the characteristics of the network. Second, it is presented that the P2P electricity trading process with the system loss charge scheme based on the cost-causality principle and verified its effectiveness in terms of reducing system loss. Third, it proposes a network operation scheme with violation charge that guarantees higher market efficiency than the fixed violation charge method while enhancing network reliability. Further, it is more practical to be implemented by utilizing sensitivity factors without solving the power flow equation.

7.2 Future Works

One of the key assumptions of this study is that market participants engage in cooperation to ensure cost-effective grid operation in response to network charges. Based on this assumption, the market participant's market strategy model used in this dissertation adjusts trading volumes according to changes in network charges, with the aim of facilitating cooperation for network operation. However, it is important to acknowledge that this assumption may not always hold in real-world scenarios. For instance, market participants with malicious intent may tolerate network charges and cause excessive system losses or network violations by engaging in transactions. Cost-efficient and reliable network operation necessitates managing such transactions, but the proposed operation scheme in this dissertation has the limitation in dealing with them. Furthermore, from a modeling perspective, formulating an optimization-based market problem that include market participants with such characteristics is challenging due to the non-linear and non-convex nature of their transaction models. Therefore, it is imperative to develop improved transaction mechanisms that can restrict transactions by malicious market participants and foster cooperation among market participants for network operation.

Another assumption made in this dissertation is that trading information exchange among market participants is synchronized. In other words, all market participants exchange trading volume simultaneously, and system loss charges and violation charges are determined based on the network state at the moment when information is exchanged. However, in reality, such information exchange occurs asynchronously, introducing the possibility of missing information during the estimation of the network state based on trading volume information. Therefore, improvements are needed in the trading mechanism to account for this missing information when imposing network charges.

Finally, the Shapley value is utilized for loss allocation because it provides a fair method to distribute costs and benefits imposed on participants in a cooperation. However, computation of the Shapely value requires figuring out all possible combinations of marginal contributions from participants and determining their average values. This process leads to exponentially increasing computational complexity as the number of participants grows. In this study, an algorithm was employed to simplify the calculations by utilizing the fixed current of each node, thereby mitigating this limitation. However, it should be noted that this method is specifically applicable to radial networks and may have restrictions when applied to mesh networks. Therefore, efficient computational methods need to be developed to allocate system loss charges using the Shapley value in mesh networks.

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초 록

개인 간 전력 거래 시장은 분산 전원의 도입으로 인해 새로운 배전계통 운영방식으로 고려되고 있다. 이 시장의 거래 메커니즘은 중앙 집중형과 분산형으로 분류된다. 다양한 거래 목적을 가진 시장 참여자의 수용성과 시장의 확장성 측면에서 강점을 가진 분산형 메커니즘에 대한 관심이 집중되고 있다. 그러나, 오직 시장참여자들의 이익만을 목적으로 거래가 수행되는 분산형 시장 메커니즘 기반의 개인간 전력거래 시장에서 안정적이고 효율적인 계통운영을 위한 배전계통 운영자의 역할은 제한된다. 이러한 상황에서 거래로 인해 발생하는 과도한 계통 손실과 계통의 물리적 제약 위반과 같은 문제가 발생할 수 있다. 본 연구에서는 이러한 문제점을 개선하기 위해 거래가 수행되는 동안 시장 참여자들에게 분배되는 계통손실비용과 계통제약 비용을 가격 신호로 활용하여 개인 간 전력 시장의 효율성을 높이고 계통의 안정성을 확보할 수 있는 배전계통운영자의 배전계통운영방안을 제시한다.

본 연구에서 제시한 계통손실비용 분배방법은 원인자 부담 원칙에 따라 설계된다. 개인간 전력거래시장의 Nash 균형조건과 최적의 시장결과를 만족하는 Stationary 조건이 서로 동치임을 증명하는 방법을 사용하여 원인자 부담 원칙에 따라 분배된 계통손실비용이 개인간 전력시장에 적용되었을 때 최적의 시장결과에 부합함을 보였다. 또한, 계통손실비용을 균등 분배하는 것은 최적의 시장조건을 만족하지 못함을 확인하였다. 그리고 비용유발원칙에 따른 계통손실 비용분배를 설정하는 방법으로 계통의 손실민감도와 시장참여자의 거래량에 대한 평균 손실기여도를 추정하는 Shapely value 방식의 손실가격 설정방법을 제안하였다.

분산형 메커니즘 기반의 개인간 전력거래시장에서 배전계통운영자의 계통손실 비용분배를 위한 거래 메커니즘을 설계하였다. 계통손실가격에

따른 시장참여자의 효용함수를 정의한 후, 최적화 문제로 시장 모델을 설정하였다. 이 문제를 시장참여자간 거래정보 교환 방식의 분산형 메커니즘으로 해결하기 위하여 Dual gradient method 와 Dual decomposition 기법을 사용하여 거래 절차를 수립하였다. 배전계통운영자는 시장참여자가 수렴된 거래결과를 도출하는 과정에서 거래량 정보를 통해 추정한 계통손실비용과 분배된 손실비용을 시장참여자에게 고지한다. 이를 고지 받은 시장참여자들은 손실비용을 고려한 최적의 거래량과 거래가격을 설정하고 이를 거래상대와 교환한다. 이 과정은 수렴된 거래결과를 도출할 때까지 반복된다.

계통제약 비용분배를 활용한 거래절차 역시 반복적인 거래정보 교환을 통해 수렴된 거래결과를 도출하는 방법으로 설계된다. 이 과정에서 사용되는 배전계통의 특성을 반영한 조류 · 전압 민감도는 계통의 상태와 물리적제약 위반을 추정함에 있어 높은 정확도를 제공하고 비선형 전력조류방정식을 대체할 수 있어 시장확장성을 제공한다. 거래정보의 교환과정에서 거래로 인해 발생이 예상되는 계통제약위반에 대해서 배전계통운영자는 비용을 설정하고 이를 민감도를 사용하여 분배한다. 즉 계통제약을 많이 유발할 것으로 추정되는 참여자에게 더 많은 비용이 분배될 수 있음을 고지하여 참여자가 계통제약을 발생하지 않는 범위내로 거래를 유도한다.

제안된 배전계통운영자의 개인간 전력거래에 대한 계통운영방안은 IEEE 33 시험계통에 시험용 거래 데이터를 사용하여 검증하였다. 모의실험결과에 따르면 비용유발 원칙에 따라 계통비용 분배를 수행한 거래결과가 손실비용을 균등하게 분배한 거래보다 계통의 손실이 감소하여 운영효율이 증가된 결과를 보였다. 계통제약 비용분배를 사용한 계통운영방안이 반영된 시장의 실험결과에 따르면 계통제약 비용을 균등하게 분배한 시장보다 시장의 거래결과에 따른 사회적 효용이 증가하고 전압과 조류제약을 유지하면서 더 많은 거래가 시장에서 발생될 수 있음을 확인하였다. 또한, 조류 · 전압 민감도를

사용한 본 연구의 운영방안이 Power transfer distribution factor (PTDF)를 사용한 선행연구의 운영방안보다 조류를 추정함에 있어 더 높은 계산 정확성을 제공하여 조류제약을 관리함에 있어 뛰어난 성능이 있음을 보여주었다.

본 연구는 분산형 메커니즘 기반의 개인간 전력거래 시장이 배전계통에 시행이 예상되는 상황에서 배전계통운영자의 계통운영방안을 제시하였다. 이를 통해 배전계통운영자는 효율적이고 안정적인 계통운영을 통해 개인간전력거래 시장의 지속성을 확보할 수 있다. 또한, 기존의 수직적이고 일방적인 공급방식에서 능동적이고 양방향 전력조류가 발생하는 배전계통환경으로 변화에 대비하여 계통운영을 위한 새로운 가이드라인을 제공할 수 있을 것으로 기대한다.

주요어: 계통 비용분배, 개인 간 전력거래, 배전계통 운영방안,

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