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Cost allocation in integrated community energy systems - A review

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ABSTRACT

Integrated community energy systems (ICESs) emerged in the reform of local energy systems during the energy transition. Cost allocation within an ICES is one of the key issues determining the success of ICESs. The costs should be allocated fairly among the members of a local energy community. However, not much research has been directed towards cost allocation in local energy systems. In this paper, firstly, we compare ICESs with large power systems in terms of their physical and cost structure. Secondly, learning from experience with electricity tariff design, we derive cost allocation approaches for ICESs. To this end, we summarize tariff design objectives, cost allocation procedures and the underlying regulatory principles for major tariffication approaches and discuss how these concepts may be applied to cost allocation in ICESs. Discussions on the lessons learned so far and application issues in ICESs are included in this paper. This review paper paves the way for application of fair cost allocation in ICESs by providing a systemic framework.

1. Introduction

1.1. Background

With the growing concerns over energy depletion and environmental protection all over the world, more and more attention is being paid to energy transition towards renewable energy sources (RESs), energy efficiency improvement, and CO2 emission reduction [1,2]. Some countries are already responding to this problem by making some commitments towards climate and energy policies. The European Union set its targets for 2030 to increase the penetration of renewable energy to 32%, improve the energy efficiency at least to 32.5%, and reduce at least 40% greenhouse gas emissions compared to 1990 levels [3,4]. Integration of distributed energy resources (DERs) plays an essential role in the transition of future energy systems. DERs are typically smaller in scale than the traditional generation facilities, for instance, photovoltaics (PV) and storage [5,6]. DERs provide flexibility not only in terms of energy generation and consumption but also in the reform of energy systems by making them decentralized [7]. Local communities play a key role in the transition of energy systems by implementing DERs and changing their roles from consumers to prosumers [5,6]. Energy systems are changing from one large national power system to local energy systems in cities, villages, and communities, where demand and supply are met at the local level [8].

Integrated community energy systems (ICESs) emerged in the transition of local energy systems by integrating local communities and local DERs [9,10]. ICESs focus on the local landscape by managing local energy generation, delivery, exchange to meet local energy demand either with or without grid-connection. It aims at improving the performance of local energy systems, for example, by improving energy efficiency, increasing DERs penetration, reducing energy costs, and contributing to CO_2 reduction. Different actors are included in ICESs, such as investors, local community members (consumers and prosumers), energy service providers, and system operators, which add social attributes to ICESs. From economic perspectives, these actors are also considered stakeholders in ICESs. Costs and benefits, as well as advantages and disadvantages, must be shared among them fairly. Therefore, ICESs are considered comprehensive energy systems, which add technical, economic, environmental, and social merits to the local energy system landscape [11–13]. ICESs provide the opportunity for local communities to take full control of the energy systems since they can invest, produce, sell, purchase and consume energy inside the community.

Since ICESs are a rather new topic, many challenges exist in their implementation, which vary from technical, socio-economic, environmental to institutional issues [13–15]. For instance, high initial investment costs may hamper the development of ICESs. Furthermore, split-incentive problems make some members net beneficiaries, whereas others will become net contributors. The split-incentive problem in ICESs is often caused by the fact that the party which has made

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the investment does not automatically get the benefits that belong to it [16,17]. It is of great importance that costs and benefits are allocated in a fair way in an ICES, and therefore, this is an important factor affecting the success of an ICES.

The investments made in ICESs vary from individual household level to community level. In principle, the costs should be paid by those who consume energy and use energy-related services in the system, and the benefits should be assigned to those who made the investments [13]. A fair cost and benefit allocation in ICESs is the key issue that determines the success of ICESs. The benefits include:

- It helps to enhance the cooperation of local community members and thus the engagement of the local community in its entirety. Local communities are the fundamental actors that ICESs do not exist without their participation. Therefore, it is important that local community members can remain in ICESs.
- It helps to avoid free-rider behavior with certain members being able to use the service for free or at too low a cost, while others are paying too much. Avoiding free-rider behavior contributes to fairness when allocating costs and benefits, which is always the main issue, no matter in whichever system.
- A well-designed pricing structure will send economic signals to users that encourages them to use energy and energy services in the most cost-efficient way. By doing so, local community members can know their consumption behavior well and how their energy bills are determined.
- It contributes to the optimal operation of ICESs in the short-term and sustainable development of ICESs in the long-term. A well-designed cost allocation follows the objective of economic efficiency, which further makes the system work optimally to save costs. In addition, it also encourages local community members to remain in ICESs for a longer time.
- It promotes social acceptance of local communities towards ICESs since it considers the preferences and opinions of the local community members. Social acceptance is far more important in the context of ICESs since local community members are the essential components. Their benefits should be well protected, and they also should pay for the costs for the energy and service they use as well. It should be made sure that each member is treated fairly.

1.2. Research gap and contributions of the paper

There are presently no criteria and approaches on how to allocate the costs in a local energy system, especially in ICESs mainly equipped with local DERs. In large power systems, cost allocation is the outcome of a regulatory process of allocating electricity supply costs to customers by electricity tariff, applying accounting and regulatory principles. There are many successful examples of cost allocation methods applied in tariff design in large power systems. Some of the issues discussed in this context are: objectives [18], regulatory procedures [19,20], regulatory principles [20–22] and cost allocation keys [23,24].

In recent years, consumers are becoming prosumers with the penetration of DERs, which has changed the way the distribution network system being operated and managed. This has put cost recovery and fair and efficient allocation of distribution network costs at risk [21]. The traditional pricing methods are not suitable for the new system as they do not reflect the costs and benefits that belong to consumers, prosumers, and the distribution network [25]. It has become a necessity to redesign the distribution network tariff as it is the pricing signal received by the end-users. Many cost allocation methods are proposed in this transition process to cope with the problem brought by the penetration of DERs. A two-part network charge design was proposed in Ref. [21], which includes two components: a peak coincident network charge and a fixed charge. The peak coincident network charge is obtained by allocating costs according to their contribution to peak demand during peak hours, and the fixed charge is obtained by allocating the remaining network costs by following Ramsey pricing principles to ensure cost recovery. It concluded that the proposed design could send efficient economic signals to customers during peak network hours while ensuring cost recovery. Network costs are classified as fixed, network-usage-related, and loss-related costs in Ref. [25]. These costs are allocated based on the variant MW-mile method, which is associated with power contribution and losses in each branch of the network. The two proposed methodologies have the same characteristic that they combine the single distribution network charge method and follow regulatory principles to achieve regulatory objectives. In this paper, these cost allocation approaches applied in distribution network tariff design are reviewed for application as cost allocation methods in ICESs.

In order to achieve a successful cost allocation in ICESs, a comprehensive review of tariff design issues in large power systems is presented in this paper. The novelty of this paper includes two parts: the first is to investigate how to translate the concept of tariff design into cost allocation in ICESs. The second is the discussion of the experiences learned and possible modifications to the application of cost allocation methods to cost allocation in ICESs. The major contributions of the paper are the following:

- Firstly, the key issues in tariff design in large power systems are presented, and discussed how the concept of tariff design could be translated to cost allocation in an ICES. The concept of tariff design in large power systems can easily be applied in ICESs and provides a systematic framework on how to perform cost allocation in ICESs.
- Secondly, the mathematical formulation, characteristics, and applications for each cost allocation method are illustrated in detail, followed by a discussion of the experiences learned and application issues. The discussion also includes a comprehensive analysis of the potential problems that have impacts on cost allocation in ICESs and possible solutions. These methods are potential options for allocating costs in ICESs.
- Thirdly, the main challenges that might meet in the process of cost allocation in ICESs are proposed and dis-cussed, possible solutions are recommended.

1.3. Structure of this paper

This study is structured as follows: Section 2 presents a comparison between large power systems and ICESs. Section 3 provides a detailed overview of electricity tariff design which includes definition, objectives, regulatory procedures, tariff structure design, and regulatory principles, followed with a discussion of how these concepts can be applied in the case of ICESs. Section 4 reviews the widely used cost allocation methods in tariff design in large power systems and how they are implemented and their characteristics. Following with a discussion on the experiences learned and application issues in ICESs. New concepts are derived based on the analysis of these methods. Section 5 discussed several issues that may have impacts on cost allocation in ICESs. Finally, Section 6 contains a conclusion and outlines future work recommendations.

2. Comparison between large power systems and ICESs

2.1. Large power systems

In large power systems, power is generated at central power plants and transmitted over high voltage lines to distribution stations, and then supplied to the end-users. The activities involved in the supply of electricity from generation to the end-users include: generation, transmission, distribution, and supply (retail) [26,27]. In a competitive electricity market, generation and supply become competitive activities, the energy price is determined by the electricity market, and transmission and distribution activities are considered natural monopolies under regulation [27,28]. Generation in large power systems takes place in large-scale power plants, such as nuclear, gas, and oil-based generators, which are centralized and controllable. Generation can satisfy load demand at all times with an appropriate dispatch of these power plants. In recent years, large-scale solar panels and wind turbine power plants are being integrated into large power systems to substitute the traditional sources of energy.

The costs incurred in large power systems include the costs for conducting generation, transmission, distribution and supply (retail) activities. All these costs are listed in the company accounts. They include the capital expenditures and operational expenditure, which covers the cost of operation and maintenance (O&M), and other overhead costs. A third cost category represents the fuel costs and energy purchase costs. Since these latter are proportional to the energy produced or purchased, they are considered variable costs. Other costs are considered fixed costs [29].

Typically, in a regulated setting, the total revenues of an operator are covered through the (regulated) tariffs – apart from activities which are left to a liberalized market. Cost recovery is thus guaranteed, as well as a fair allocation of these costs to system users, which is reflected in the tariff design. The application of appropriate and fair tariffs provides short-term and long-term signals to system users, thus contributing to the long-term stability and efficiency of the energy system.

2.2. Integrated community energy systems

ICESs are local community energy systems consisting of two fundamental components: local DERs and a local community [9]. A general framework of an ICES is shown in Fig. 1. The power is generated by local DERs (such as solar panels and small-scale wind turbines) and directly delivered to local consumers. ICESs could work in off-grid operation mode to achieve self-sufficiency and grid-connected operation mode to get support from large power systems. However, it is required to be accounted that off-grid ICESs are hard to achieve at this moment because of the high cost of DERs and intermittency of RESs generation. It has the potential to be self-sustaining in the future. Customers in ICESs have the right to invest in DERs, making them prosumers. ICESs also enable local energy exchange and sharing activities. Prosumers can trade their surplus energy in the community, while they are required to purchase energy in ICESs. Moreover, consumers can use the energy shared by prosumers. ICESs act as an aggregator in the context of this study, dealing with the activity of energy exchange and collective energy purchase from or sell to the grid. Energy storage is used to supplement deficit energy when DERs generation is insufficient and store surplus energy from RESs generation. Energy storage is the main enabler to deal with the intermittent problem of RESs generation and makes ICESs self-sufficient.

The total costs of ICESs contain all the cost items associated with the activities that are necessary to supply energy from generation to the end-users, which include capital expenditures, operational expenditures, local network costs (for connecting the members in the local energy system) and, if applicable, fuel costs. These are major costs for off-grid ICESs. For grid-connected ICESs, besides the costs mentioned above, the capital costs involved may also include grid connection costs and network service-related costs. Network service-related costs are used for getting support from the grid, such as maintaining system reliability and energy balance, ensuring power quality and voltage control, and ancillary services. There may be a cost component for the energy exchange, i.e., for energy purchase costs from the national system as well as revenues from selling energy to the national system. Finally, there are additional costs for operating the community energy management system [13]. Other costs are all fixed except for the energy purchase costs and energy selling benefits. Once these facilities are installed, they can be operated during their technical lifetime. Especially for DERs, the annual costs for energy generation are limited.

2.3. Comparison

This subsection summarizes the similarities and differences between large power systems and ICESs. Table 1 shows the physical differences between the two energy systems. Large power systems are centralized and generation is far away from the end-users. Transmission and distribution networks are used to transport power at a high voltage from generation to the end-users at a lower voltage. ICESs are in small-scale, electricity is locally generated and locally consumed. From the system operation perspective, system congestion exists in large power systems, while this problem does not exist in ICESs. The customers in large power systems are usually categorized into three groups: commercial, industrial and residential consumers. In ICESs, customers are local residents. They can choose to invest in DERs or not. Energy exchange is enabled between individual community members in ICESs. For large power

Table 1
Comparison between large power systems and ICESs in terms of system formulation.

	Large power systems	ICESs
Generation	Large centralized power plants (coal/gas-based power plants with large-scale PV and wind turbine power plants)	Small-scale DERs (solar panels/small-scale wind turbines)
Network	Transmission (high and medium voltage) network Distribution (medium and low voltage) network	Local (low voltage) network for interconnection and grid-connection
System scale	From national to neighborhood level	Local community
Customers	Consumers (Commercial, industrial and residential customers)	Consumers and prosumers (Local community customers)
Regulator	Included	Not included

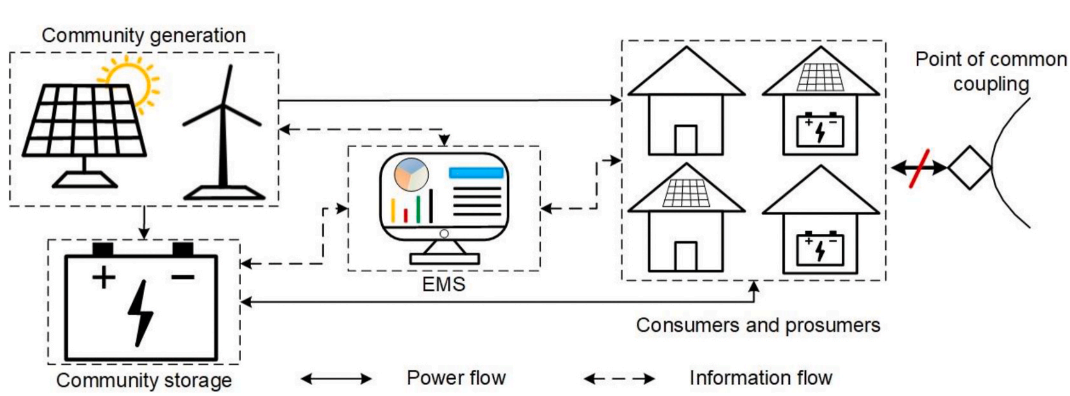

Fig. 1. A general structure of an ICES.

systems, with the development of smart grids in recent years, consumers with DERs are allowed to form a virtual power plant, and this virtual power plant aggregates the capacities from DERs to trade in the electricity market. The grid also enables energy trading, but still on a large scale. In large power systems, the regulator makes decisions on tariff design according to the regulatory principles. In contrast with large power systems, in ICESs, there is no regulator assigning the costs to the members.

A comparison of the major cost items for both energy systems is shown in Table 2. In large power systems, generation costs take a large majority and vary with the amount of electricity generated. While in ICESs, the costs are classified between different grid-connection modes. For off-grid ICESs, the costs are almost fixed. Variable costs are included in grid-connected ICESs for purchasing energy from the grid. The costs in ICESs have the characteristic of Capex intensive.

In summary, ICESs have the same function as large power systems to provide electricity and related services to the end-users. In many ways, ICESs are smaller versions of the grid. However, ICESs differ in that they are close to electricity generation and consumption, which result in efficiency increases and loss reductions [9,13]. ICESs are more environmentally-friendly and contribute to CO_2 emission reduction, as most of the generation is from RESs. ICESs provide much more flexibility to consumers. They have the right to take charge of their energy systems. To some extent, ICESs increase power reliability as they are decentralized systems. ICESs also offer the possibility for rural electrification in remote areas, which is difficult for large power systems to reach due to the long transmission distance and high costs. Local community members take active participation in ICESs, as they are the main entity and they can invest in DERs and make decisions. ICESs focus on the engagement of local community members, and there is no regulator in ICESs, the community itself needs to find a suitable manner to allocate costs fairly among local community members. There is not much literature on how cost allocation in ICESs may take place. However, there are many examples of cost allocation methods used in tariff design in large power systems. By reviewing principles and methods of cost allocation in tariff design in large power systems, principles and methods that may be applicable to ICESs are identified.

3. An overview of electricity tariff design

This section reviews the objectives, regulatory procedures, tariff structure design and regulatory principles of tariff design in large power systems.

Table 2
Major cost items in large power systems and ICESs.

	Large power systems	Off-grid ICESs	Grid-connected ICESs
Generation costs	Capital costs (fixed) O & M costs (fixed and variable) Fuel costs (variable)	Capital costs (fixed) O & M costs (fixed)	Capital costs (fixed) O & M costs (fixed) Energy purchase costs (variable)
Network costs	Transmission network costs (fixed) Distribution network costs (fixed) O & M costs (fixed)	Local network interconnection costs (fixed)	Local network interconnection (fixed) Grid connection costs (fixed) Grid supportive service costs (fixed)
Other costs	Taxes and regulation costs (fixed) (Metering and billing)	Customer management costs (fixed) (Metering and billing)	Customer management costs (fixed) (Metering and billing)

3.1. Electricity tariff

The electricity charges or prices paid by consumers are also called electricity tariffs, because they are determined by regulatory authorities. Tariffs are basically a group of charges reflecting the costs of each activity. These charges consist of energy prices, transmission network charges, distribution network charges and regulated taxes. As shown in Fig. 2, before the liberalization of electricity market, all these charges paid by the end-users are determined and set by the regulatory authorities [30]. In the liberalized electricity market, generation and retail are deregulated and become competitive business activities, while transmission and distribution networks are still considered regulated natural monopolies [31]. The energy generation and retail activities are left to the market, any investors are allowed to install new power plants freely and sell electricity at the wholesale market price. The electricity price is the equilibrium price which is determined by the supply and demand curve in the electricity market. Consumers can purchase energy from any generation companies or retailers at a freely established price in the electricity market.

A tariff is the interconnection between electricity companies and the end-users. In order to achieve a successful tariff design, many key issues are included in electricity tariff design. These key issues are summarized in Fig. 3.

Firstly, clear and concise objectives should be identified before allocating costs. Secondly, detailed processes are required to make sure the costs are allocated in a proper manner. Thirdly, a clear and informative charge structure should be provided to the end-users in order to ensure they are well informed of their billing structure. Finally, regulatory principles are essential guidelines to achieve the desired objectives and outcomes since distribution networks are not liberalized, and their prices should be regulated. In the following section, each of these issues will be elaborated in detail.

3.2. Objectives

Tariffs represent the financial settlement for the services offered by the power system to consumers. A well-designed tariff should be able not only to promote optimal utilization of the energy system in the short-term, but should also help to make the investment sustainable in the long-term. In general, there are two main objectives that need to be realized in tariff design. The first is to recover the total allowed costs [19,31]. In a liberalized electricity market, the cost recovered is for network-related businesses. In general, this is the basic requirement and the most important criterion to follow in order to make sure these activities are economically feasible. By doing so, the power sectors can provide energy to the end-users in a sustainable manner. In addition, this also contributes to attracting future investments, extending and updating the existing infrastructures, and providing high-quality energy to the end-users with the increasing demand.

The second objective is to send the right economic signals to the end-

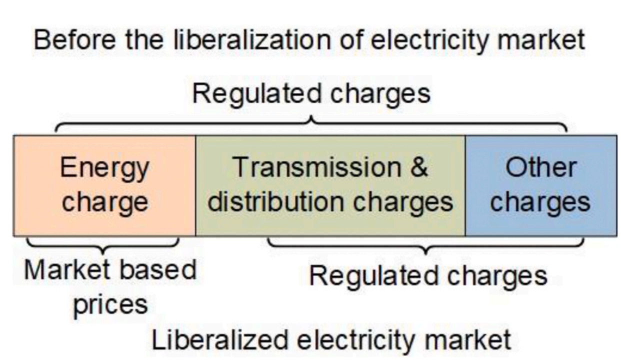

Fig. 2. Electricity tariffs before and after the liberalization of electricity market.

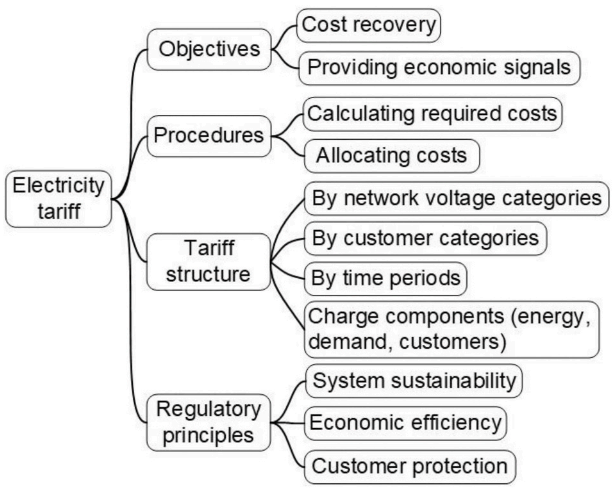

Fig. 3. Key issues in electricity tariff design.

users [19,31]. A well-designed tariff could lead the consumers to consume electricity efficiently, such as shifting peak demand to off-peak hours. This is beneficial to the end-users, they can adjust their consumption behaviors and save energy bills by the provided economic signals. In addition, cost reflectivity is often the main goal of tariff design, which reflects the contribution of each network user to the cost of the network [32]. It also provides economic efficient signals to the end-users by informing them how they are charged and how their consumption behaviors affect their energy bills. Cost reflectivity is a very important criterion in tariff design, it can be used to evaluate how well the tariff is designed.

The two objectives are the ultimate goals regulators require to address and achieve. They not only protect the rights of the various actors in power systems, but also balance the benefits among them.

3.3. Regulatory procedures

Tariff design for utility services follows a standardized procedure. The procedures for realizing tariff design mentioned in related literature are more or less the same. In general, there are two steps involved in the process of tariff design. The first step is to calculate the total allowed cost, which has to be recovered through tariffs [19,20]. Two phases are involved in this step: (1) identifying the costs and investments, (2) establishing the allowed rate of return, to provide investors with suitable remuneration for their investment. The second step is to allocate the costs to the end-users. Cost allocation is a very important procedure in tariff design, it conveys information about how the costs are incurred and how they are allocated to each type of consumer [33,34]. Two phases involved in this step [19]: (1) defining the tariff structure and (2) calculating the final charges.

The two steps in tariff design are consistent with the objectives defined in 3.2. The first step of calculating the allowed costs is also aimed to ensure cost recovery. When allocating costs to the end-users, economic signals are also provided to them. Therefore, the second step covers the second objective required to be achieved. The procedures reviewed above are not only the basic but also the essential parts in tariff design.

3.4. Tariff structure design

The electricity tariff presents an economic signal to the end-users, which reveals how their consumption behaviors affect their energy bills. It is of great importance to design an informative tariff structure. The structures should contain different charge components, and they should have a large impact on the system costs [20]. In addition, the structure of the tariff should be concise and simplified, while revealing the underlying complexity of rate calculation and energy billing costs [34]. Tariff structures should include the drivers that cause the system costs and reflect the underlying cost structure [19,20,35]. Typically, the components in electricity tariffs include [19,36]: (1) an energy charge (€/kWh) (2) a demand charge (€/kW) and (3) a fixed charge (€/period). The energy charge refers to charging the consumers based on their energy consumption (kWh) during the billing periods. The demand charge refers to that the electricity payment is determined by consumers' peak demand (kW) during the billing periods. The fixed charge is not relevant to the customers' energy consumption, it is meant to cover the infrastructure and delivery costs [24].

In addition, load profile varies according to the time of day. Time difference has a major impact on the system costs. Tariffs should take into account time differences, for instance, time-of-use (ToU) energy price [37–39], real-time price or critical peak price [30,40]. It is beneficial to consumers if they are provided with the time-based pricing signal, in such a way that they can further react to demand response. The network capacity should be designed such that it can satisfy the load demand at all times, while a large portion of the network capacity is only used in peak hours, which only lasts for a few hours each year. Therefore, most of the network costs are invested for peak hours. The definition of time period varies between different customer categories. For example, peak and off-peak time periods are applied to commercial and industrial customers in general. It is essential to take different time periods into account in tariff design.

3.5. Regulatory principles for distribution network tariff design

In large power systems, transmission and distribution are regulated activities. This regulation follows certain regulatory principles, which are essential to arrive at a proper tariff design. These are also the guidelines that tariff design should follow. These principles have already been mentioned and discussed in many research papers. They are classified into three categories: system sustainability principles, economic efficiency principles, and consumer protection principles [21,41], which are presented in Fig. 4.

- **Sustainability** It is aimed to ensure that costs are fully recovered through the tariff and that the power sector is break-even and economically viable. This is the basic principle of tariff design, and it is used to protect the benefits of electricity companies. Electricity companies recover the required costs to achieve sustainable development and attract new investments [19]. It is easy to measure to which extent the tariffs satisfy sustainability according to the costs recovered through them.

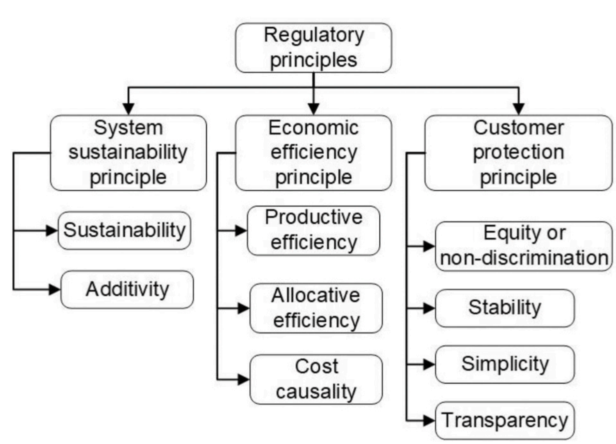

Fig. 4. Summary of regulatory principles.

- **Additivity** It is designed to make sure that the sum of various charges equals the total revenue requirement. Tariffs are designed for different activities, which include: generation, transmission, distribution, and retailing. The sum of these tariffs should provide adequate revenues for the electricity companies [24,34]. Costs are additive, it is easy to follow this principle.
- **Productive efficiency** It aims to make sure that electricity and related services are delivered to the end-users at a minimal cost while meeting quality standards [23]. By doing so, the total system costs are also controllable, thus incentivizing efficient investment. Productive efficiency requires power systems to work in the optimal operation condition.
- **Allocative efficiency** It aims to encourage consumers to consume energy efficiently. Allocative efficiency is concerned with the optimal distribution of electricity and related-services [21]. In classical economics, allocative efficiency occurs when the price of the goods equals the marginal cost of generation. This is the ideal point, which is beneficial both to consumers and producers. Allocative efficiency leads to efficient usage of energy and existing infrastructures of the power systems. Productive and allocative efficiency are the two main aspects of economic efficiency, which are used to ensure efficient resource allocation. Both principles are important in order to improve economic efficiency overall.
- **Cost causality** It is used to ensure that tariffs accurately reflect each user's contribution to power system costs [42,43]. Costs should be allocated to the drivers that cause them. For instance, generation activity is both energy- and demand-related, since it is required to generate enough energy and meet peak energy demand with the high capacity requirement as well. The principle of cost causality makes the tariff much more robust.
- **Equity or non-discrimination** Consumers in the same group should be charged at the same rate for the same amount of use of energy and service, no matter how they utilize the energy, to ensure equity [20,44]. This principle is used to ensure the end-users in the power system are treated fairly, without any discrimination.
- **stability** It aims to make sure that tariffs remain stable in the short-term and gradually change in the long-term, so as to reduce regulatory uncertainty [45].
- **Simplicity** It is used to make sure that the adopted methods and the results of cost allocation should be as easy as possible to understand [32].
- **Transparency** The process and selected method for tariff design should be transparent to all users. In addition, how the consumers are charged should be clear to them [36].

However, some of the principles conflict with each other, for example, the economic efficiency principle may violate the principle of equity or non-discrimination. Generally speaking, it is not a simple task to set an efficient tariff. Tariffs must comply and achieve a balance between these conflicting regulatory principles, and they should follow at least the three principles: cost recovery, non-discrimination, and transparency [36]. Even though it is hard to have an ideal tariff that follows all the principles, they provide a guarantee to arrive at a proper tariff design at least.

3.6. Applicability to ICESs

An ICES is a small-scale energy system, it has the same function as a large power system to supply energy from generation to the end-users. After years of development and progress, a mature systematic framework has been formed to design tariffs for a utility electricity system under regulation, both in theory and practical implementation. However, there is not much theoretical research on allocating costs in ICESs. The work done in large power systems provides sufficient theoretical support on how to allocate costs in ICESs without regulation. The key issues reviewed in tariff design provide a systematic framework for guiding how to allocate costs in ICESs. In this section, the lessons learned and applicability possibilities from tariff design in large power systems are discussed and summarized.

Various stakeholders are involved in ICESs, the benefits of each party should be guaranteed. From the perspective of investors, the investment made by them should be recovered to ensure sustainable investment from investors and the development of ICESs, which is consistent with the objective of cost recovery in large power systems. Consumers are expected to be informed of sufficient information for their energy consumption, for instance, real-time pricing or day-ahead pricing, then they have enough time to schedule energy consumption. This will lead to efficient energy consumption, thus help them to save energy costs and improve energy efficiency. Therefore, the second objective of sending economic signals to the end-users is also required in ICESs. The engagement of local community members is essential in the formulation of an ICES. Their opinions and suggestions should be taken carefully into account. The success of cost allocation in ICESs is largely dependent on the social acceptance of local community members. Fairness is a very important issue that large utility entities are also dealing with tariff design [41]. This is also the goal that ICESs require to achieve. Costs should be allocated to those who incurred them, and benefits should accrue to those who made them to avoid free-rider behavior and make it socially acceptable to local community members. It is one of the most important factors that affects social acceptance by local community members. Therefore, along with the objectives mentioned above for tariff design, social acceptance should be taken into account in the objectives and further developed.

The procedures in tariff design in large power systems provide a fundamental framework on how to allocate costs in ICESs step by step. While considering the context of ICESs, the following items should be carefully considered in the process of cost allocation in ICESs, include: (1) Identify how much costs and benefits should be allocated (recouped) and distributed (2) Deliver information about how costs are incurred and how the benefits are accrued (3) Identify the parties to which costs and benefits should be allocated (4) Present how costs and benefits are allocated (5) Send information of the final charges to customers to promote efficient energy use and ensure effective investment. Each item should be explained comprehensively to make it clear to the various stakeholders in ICESs.

The tariff structure in ICESs is determined by the cost allocation method adopted. Since there is no universal cost allocation method, therefore, the tariff structure is not definite in ICESs. However, it should be well-formulated in order to provide sufficient information to the end-users and reflect costs. By doing so, they can fully understand how their energy consumption is charged.

Besides these issues, the regulatory principles proposed in tariff design are also applicable in ICESs. Regulators make these regulatory principles to regulate tariffs, taking into account the benefits and rights of different stakeholders in large power systems. Similarly, these principles can also be used to regulate cost allocation design in ICESs to achieve the desired objectives and arrive at a proper charge. They can also be regarded as the criteria to evaluate how well cost allocation is designed in ICESs.

4. Review of cost allocation methods

This section reviews cost allocation methods applied in tariff design in large power systems. Each method is explained and the underlying principles are indicated, as well as its advantages and disadvantages. Finally, the application of each method in an ICES is discussed.

4.1. Flat energy pricing method

4.1.1. Approach

This method allocates costs according to the total amount of energy consumption, irrespective of the time of energy consumption [37,39, 46]. It charges consumers at the same electricity price all the time. It allows the utility companies to break even because the total cost includes both fixed and variable costs [47]. It is the most straightforward method for calculating energy price: dividing energy-related costs by the volume of total energy consumption [48]. Consumers pay electricity bills at a flat rate per kWh. The flat energy price P (€/kWh) is calculated as:

$$P=\frac{\mathrm{TC}}{\sum_{i=1}^{N}\sum_{h=1}^{T}E_i(h)} \tag{1}$$

where TC (€) is the total cost, $E_i(h)$ (kWh) is the energy consumption in hour h of customer i, N is the number of customers. The energy bill of customer i in time period T is:

$$C_i=P\times\sum_{h=1}^{T}E_i(h) \tag{2}$$

4.1.2. Advantages and disadvantages

The advantage of this method is that it is simple to calculate and easy to understand. The drawback of this method is that the price is flat in all consumption periods. It does not reflect the time difference. Under this tariff, consumers do not have the incentive to shift energy consumption from peak hours to off-peak hours. This method does not reflect the actual utilization of the network when applied in a distribution network. Because the investment in the distribution network is peak-capacity-related, and the networks are designed in such a way that they can satisfy load demand at every instant. However, flat energy pricing is one of the most popular pricing mechanisms employed in many countries and is accepted by regulators [33,49].

4.1.3. Applicability to ICESs

This method is easy to apply in cost allocation in ICESs. The parameters needed are total cost and total energy consumption in a certain time period. Consumers pay the cost at the flat energy price according to the amount of energy consumed. Costs do not need to be classified, all the costs are considered energy-related. In order to recover the total cost and set the right energy price, energy consumption is used instead of energy generation. The problem caused by this method is that the price is obtained ex-post. It cannot be communicated to consumers beforehand. Energy generation from RESs is very high during the daytime, but almost nonexistent during night hours. Flat energy pricing balances the cost difference between peak and off-peak generation hours. It is not fair to customers who consume more during high generation hours and less in off-peak generation hours. They are compensating for customers who consume more in peak demand hours and less in peak generation hours. This problem should be taken into account in an energy system in which generation mainly comes from RESs.

4.2. Base and peak method

4.2.1. Approach

The base and peak method has a two-part allocation factor [50]. It allocates costs to the two rating periods: base and peak hours. It promotes efficient utilization of energy resources by charging higher prices in peak hours and lower prices in base hours. The base and peak method can also be regarded as a ToU pricing method. A ToU rate structure was designed for a large electric utility company in the United States [51]. It was tested on commercial and industrial consumers, and the results showed that they pay lower electricity bills than under a flat energy price mechanism [51]. The study in Ref. [37] investigated consumer behavior under a ToU tariff structure. The results showed that the adoption of a ToU tariff incentivizes consumers to shift energy consumption in peak hours to off-peak hours. In addition, a ToU tariff benefits producers by increasing their profits and consumers by reducing their energy costs. An empirical study was carried out in Ref. [52] to evaluate how customers respond to a demand-based ToU electricity distribution tariff. It revealed that households are enthusiastic to join this program by shifting energy consumption from peak to off-peak hours. These examples demonstrate that a ToU tariff is an effective pricing strategy for lowering peak demand.

This method allocates costs according the rules that costs for satisfying base demand are allocated to the two periods, and costs for satisfying peak demand over base demand level are allocated to peak hours only [50]. The costs allocated in base and peak hours are calculated as:

$$TC_{base}=TC_1\times\frac{T_{base}}{T} \tag{3}$$

$$TC_{peak}=TC_1\times\left(1-\frac{T_{base}}{T}\right)+TC_2 \tag{4}$$

where TC_1 (€) are the costs to satisfy base demand, and TC_2 (€) are the costs to satisfy peak demand over base demand level. T_{base} (hours) are off-peak hours, and T (hours) are the sum of off-peak and peak hours.

Once the peak and base hour costs are obtained, it is easy to calculate the energy price for the two periods, which are calculated as:

$$P_{base}=\frac{TC_{base}}{E_{base}} \tag{5}$$

$$P_{peak}=\frac{TC_{peak}}{E_{peak}} \tag{6}$$

where P_{base} and P_{peak} (€/kWh) are the energy prices in base and peak hours, respectively. E_{base} and E_{peak} (kWh) are the total energy consumption in base and peak hours. The hourly energy bill $C_i(h)$ (€) for customer i is:

$$C_i(h)=\begin{cases}P_{base}\times E_i(h) & h\in T_{base}\\ P_{peak}\times E_i(h) & h\in T_{peak}\end{cases} \tag{7}$$

where $E_i(h)$(kWh) is the hourly energy consumption of customer i, T_{base} and T_{peak} (hours) are base and peak periods. The energy bill of customer i in time period T is:

$$C_i=\sum_{h=1}^{T}C_i(h) \tag{8}$$

Accordingly, the base, intermediate and peak method follows the same concept as that for the base and peak method. This method takes into account the three rating periods: base, intermediate and peak hours. The costs for satisfying base demand are allocated to all three periods, the costs for satisfying intermediate demand over base demand level are allocated to intermediate and peak hours, and the costs for satisfying peak demand over intermediate level are allocated to peak hours only.

4.2.2. Advantages and disadvantages

In large power systems, it is easy to know which power plants are being dispatched during each period. Therefore, it is easy to classify the costs in each time period. The advantage of the base and peak method is very obvious, it contributes to reducing peak demand by sending economic pricing signals to customers. Customers are encouraged to adjust their consumption behavior either by shifting their peak demand to off-peak hours or by reducing peak demand directly. By doing so, customers reduce their energy bills. The appropriate time blocks need to be defined. The calculation process for this problem is much more complex. The advantages of this method outweigh its disadvantages.

4.2.3. Applicability to ICESs

Both the two (base and peak) and three (base, intermediate and peak) rating periods methods are applicable for cost allocation in ICESs. The required data are consumption data and costs in peak and off-peak hours. Smart meters are required to obtain hourly consumption data. Smart meters also make it easy to classify peak and off-peak hours. The key challenge in implementing this method is how to allocate the total costs in peak and off-peak hours separately. In the case of an ICES, the costs are almost fixed because they are based on RESs. This is different from large power systems, where different power plants can be scheduled and operated in different hours. One possible solution is to classify the total fixed costs for an ICES by using a coefficient, for instance, load factor. With the base, intermediate and peak method, it is also possible to select multiple time periods to make the method more time-reflective.

The base and peak method reflects the difference of energy price in different hours. In ICESs, generation is mostly from RESs, high during the day and low during the night. One implication obtained from this method is to modify the pricing mechanism to time-of-generation instead of ToU. A time-of-generation energy price reflects the capability of generation. Price is low during high generation hours and high during low generation hours. Load is also low in high generation hours, therefore, it is possible to adjust peak and off-peak demand. For instance, adjusting peak demand to high generation hours. This requires further investigation in terms of practical implementation.

4.3. Marginal cost pricing method

4.3.1. Approach

Marginal cost is defined as the change of total cost when producing one more unit of energy (e.g. 1 MWh). In the short-term, the capacity of the energy system is fixed, the short-term marginal cost only includes the operating costs of the existing infrastructure, without any additional investment [53–55]. Normally, this provides the hourly energy price, which could be regarded as real-time pricing [33,49,56]. In a liberalized wholesale electricity market design, the short-term marginal cost is used to set the electricity market price. This approach describes the real situation of the present scenario, however, it is volatile and does not enable recovery of the revenue required [57,58].

Long-term marginal cost is focused on possible future scenarios, it is the cost of the same increase in demand but with the option of new investment to adapt the system to new demand levels in the long-term, and follows the best investment trend [59,60]. It includes both long-term operation, investment and reinforcement costs [61]. It reflects the cost of bringing forward or deferring future investment. Long-term marginal cost provides a solution with a set of possible future scenarios instead of having many possible short-term marginal costs [20]. The long-term incremental cost approach is normally used instead of long-term marginal cost to mitigate the lumpiness of network investment. The difference between long-term marginal cost and long-term incremental cost is that long-term incremental cost refers to the total additional cost resulting from producing a certain amount of capacity (eg. 10 MW) [53,62,63].

There is no universally acceptable consensus on how marginal and incremental costs should be calculated, their mathematical formulations based on their original definitions are given in Ref. [63]. The marginal cost is calculated as:

$$MC = \frac{dC(Q)}{dQ} \tag{9}$$

where Q is the quantity of energy (kWh) or capacity (kW) supplied, and C(Q) (€) is the cost function.

Incremental cost is calculated as:

$$IC = C(Q + \Delta Q) - C(Q) \tag{10}$$

4.3.2. Advantages and disadvantages

Both marginal and incremental cost can be applied in the cost allocation for generation [50], transmission [64–66] and distribution network activities [20,31]. The short-term marginal cost pricing method provides the most economic signals to consumers according to classic economics. However, it can only recover the variable operating costs in generation and distribution activities [58,67,68]. Long-term marginal cost is more attractive in transmission and distribution network tariff design in theory, but the calculation is very difficult and future assumptions are required [65]. Neither short-term marginal cost nor long-term marginal cost can ensure cost recovery [20,69]. Therefore, the first problem incurred by these methods is revenue reconciliation or modification, which are required to recover the costs that cannot be recovered. The second problem is that these charges are calculated based on optimal expansion tools which may not be the same case in practice. For the long-term incremental cost method, it still cannot ensure the recovery of the total cost because of the lumpiness of network investment and economies of scale. Another disadvantage of long-term marginal cost is that it cannot send short-term economic signals to consumers compared with short-term marginal cost, and may lead to investment delay.

4.3.3. Revenue reconciliation

Revenue reconciliation is used to recover the cost that cannot be recovered using long-term marginal cost and long-term incremental cost. The first option is to make adjustments by applying coefficients to the rates [31,57]. The coefficients used are multiplier and additive [69–71]. The first adjustment is to multiply a ratio of the allowed costs to the marginal based-revenues [72]. Its purpose is to recover the total allowed cost. The second adjustment is to add the same amount to all rates for all customer categories and periods [31]. This method maintains the economic efficiency of the rates signal. The second option is to use a two-part tariff to recover the cost that cannot be recovered by marginal cost. The idea is that variable costs are recovered by marginal cost, and the fixed costs are recovered by fixed charges (the costs are divided by the number of customers) [49]. The third option is to make modifications to the method, for example, a coincident factor based on the long-term marginal cost pricing model has been proposed in Refs. [73,74], it can not only recover the required costs, but also encourage consumers to reduce their coincident peak demand effectively, thus reducing network congestion and investment.

4.3.4. Applicability to ICESs

Marginal cost pricing is the most efficient pricing signal from an economic perspective, however, the marginal cost for RESs is almost zero, as has been illustrated extensively in the literature [75–80]. Particularly in the case of a renewable energy source-based ICES, the short-term marginal cost is always zero in off-grid operation mode. The total cost cannot be recovered using this pricing mechanism. For a grid-connected ICES, the marginal cost is the price at which the ICES buys electricity from the grid when generation cannot meet demand. It also cannot recover the cost in the case of RESs either. The marginal cost pricing mechanism therefore cannot be applied in cost allocation in ICESs.

Short-term marginal cost shows the hourly energy price. One implication obtained from this concept is to calculate the hourly energy generation price. For instance, dividing the total cost between the generation hours equally and calculating the energy price based on the energy generation at that hour. It violates the definition of marginal cost and cannot be called marginal cost pricing, but at least it can provide some economic signal that reflects generation capability. One of the biggest problems of using this method is whether to provide real-time or day-ahead price, because they are not the same due to the difference between real-time generation and forecast data. The costs that cannot be recovered can be left for revenue reconciliation. Another problem is how to set the energy price when there is no energy generation from RESs. Marginal cost pricing is a complicated issue both in large power systems and ICESs. It is a big topic that needs further research. However, at this moment, based on the analysis of the concept of marginal cost pricing, its drawbacks are so obvious that they outweigh its advantages. Applying this method to cost allocation in ICESs is not recommended.

4.4. Average and excess method

4.4.1. Approach

The average and excess method allocates costs using factors that combine the customers' average and non-coincident peak demands [50, 81]. It has a two-part allocation factor [82,83], the first part is the ratio of average demand of a customer and the sum of the average demand of all customers, multiplied by the system load factor (average system consumption divided by the system peak demand). The second part is the ratio of the excess demand of each customer and the system excess demand, multiplied by the complement of the system load factor (one minus the system load factor). The excess demand for a customer is the difference between the peak demand and the average consumption of the customer. The system excess demand is the sum of all customers' excess demand. The two factors are calculated as:

$$f_{1\_i} = \frac{P_{ave\_i}}{\sum_{i=1}^{N} P_{ave\_i}} \times lf \tag{11}$$

$$f_{2\_i} = \frac{P_{exc\_i}}{\sum_{i=1}^{N} P_{exc\_i}} \times (1 - lf) \tag{12}$$

$$P_{exc\_i} = P_{peak\_i} - P_{ave\_i} \tag{13}$$

$$lf = \frac{\sum_{i=1}^{N} P_{ave\_i}}{P_{peak}} \tag{14}$$

where f_{1_i} and f_{2_i} are the two-part allocation factors of customer i, P_{ave_i} and P_{exc_i} (kW) are the average and excess demand of customer i, P_{peak} (kW) is the system peak demand. lf is load factor of the whole energy system.

The final cost allocated to consumer i is:

$$C_i = \left(f_{1_i} + f_{2_i}\right) \times TC \tag{15}$$

4.4.2. Advantages and disadvantages

This method allocates costs based on the average and excess energy consumption of the customers. It does not take the consumption periods into account. The first allocator indicates the share of their average consumption in the average consumption of the whole system. The second allocator indicates the share of their excess consumption on the excess consumption of the whole system. The second allocator reflects the impact of peak demand on final costs. The economic signal provided by this method is that customers should maintain their energy consumption within the average consumption level to reduce their energy bills. The disadvantage of this method is that large quantities of data are required to calculate the allocators and final costs. The calculation process is rather complicated.

4.4.3. Applicability to ICESs

The required data are the average and peak demand of each customer and of the energy system as a whole to calculate the two allocators. It is easy to obtain these data with the deployment of smart meters. This method can be applied in cost allocation in ICESs. Customers are aware that they should pay attention to their peak demand with the introduction of the concept of this method beforehand.

The average and excess method charges customers according to their consumption levels. Based on this idea, it is also possible to derive a new approach to allocate costs: setting two charges for different energy consumption levels. For example, customers could pay at a lower price if their energy consumption is within the average consumption level, and at a higher price for the part above the average consumption level. This pricing mechanism provides energy pricing signals instead of allocating costs directly to customers. The focus is on the consumption level instead of on consumption hours. In ICESs, energy generation is mainly from RESs, energy storage is used to store and supply energy efficiently and economically. An energy consumption level based pricing mechanism can help customers make a rational decision. They can decide how much capacity of battery storage should be invested in to maintain their energy consumption below the average level. By doing so, customers can avoid unnecessary costs involved in paying for excess consumption at a higher price. The details of this new pricing mechanism should be further developed and modeled to identify its effectiveness.

4.5. Ramsey pricing method

4.5.1. Approach

The Ramsey pricing method allocates costs in inverse proportion to price elasticity [84,85]. It is considered the second-best pricing method, which is between an ordinary monopoly and perfect competition, because it is based on marginal cost pricing (which is regarded as the very best pricing method) [49,86]. It is normally used in cases in which the marginal cost is below the average cost, which would make the utility companies make losses [87]. The studies in

[68,85] analyzed the application of Ramsey pricing in Chinese and Japanese electric companies separately, both results showed that the use of Ramsey pricing increases the residential electricity price while decreasing the industrial electricity price. An optimal electricity market price is derived based on Ramsey pricing in the day-ahead Italian wholesale electricity market in Ref. [86], the results show that Ramsey pricing can improve social welfare.

The objective of Ramsey pricing is to maximize social welfare which is subjected to minimum profit constraints [68,85,88]. The mathematical expression for calculating Ramsey pricing according to research [33, 68] is:

$$\frac{P_i - MC_i}{P_i} = \frac{\lambda}{1 + \lambda} \frac{1}{\eta_i} \tag{16}$$

where P_i (€/kWh) is the electricity price for customer group i, MC_i (€/kWh) is the marginal cost of customer group i, λ is the Lagrange multiplier derived from the welfare maximization problem, η_i is the price elasticity of demand associated with customer group i.

4.5.2. Advantages and disadvantages

The advantage of Ramsey pricing is obvious, in that it can maximize social welfare. However, there are two main drawbacks of Ramsey pricing which make it hard to apply in practice [34]. The first drawback is that it is difficult to estimate the price elasticity of demand in practice. The second drawback is that it is discriminatory: because most of the costs are borne by the consumers who have an inelastic demand, it violates the principle of equity. The third is that it does not provides economic pricing signals to consumers.

4.5.3. Applicability to ICESs

Energy generation in ICESs is almost all from RESs. The marginal costs for RESs are zero [75–77], which means the equation does not bear any relationship to electricity price. Therefore, the Ramsey pricing method is not suitable for cost allocation in ICESs.

4.6. Postage stamp method

4.6.1. Approach

The postage stamp method is widely used in European countries for transmission network cost allocation [89–91]. It allocates the allowed revenue according to the magnitude of the transacted power, which is measured at the time of the system peak demand [92–95]. The transmission network price is calculated as:

$$P = \frac{TC}{\sum_{i=1}^{K} P_{peak\_i}} \tag{17}$$

where P_{peak_i} (kW) is the peak demand of transaction i. Therefore the transmission network cost for transaction *i* is:

$$C_i = P \times P_{peak\_i} \tag{18}$$

4.6.2. Advantages and disadvantages

The postage stamp is a non-power-flow-based method. The principle of this method is simple and straightforward. It is easy to calculate the transmission network cost according to the peak demand of each transaction. However, it does not take the actual system operation into account: the transmission distance, the location and the actual usage of the transmission network. The economic signals sent to transmission network customers may not be correct and efficient [62,96]. According to the study in Ref. [92], the postage stamp method is favored by investors, because the tariff is stable and predictable.

4.6.3. Applicability to ICESs

This method is usually used in transmission network cost allocation, while ICESs are focused on local community, which is at a low voltage level. The required data are the peak demand of each household and of the whole system. Even though the peak demand of each household is not as high as that of the transmission network, their peak demand differs between different household types, for example, household with one person, couple or couple with children. The peak demand of each household is measured at the time of system peak demand. This can be achieved by installing smart meters. The peak demand data cannot be obtained in advance. Information can be delivered to customers that their energy bills are determined by their peak demand. It is easy and simple to apply this method to cost allocation in ICESs.

4.7. Contract path method

4.7.1. Approach

The contract path method allocates costs according to the selected path (which is also referred to as the contract path) between the seller and the buyer [64,97]. It is also mostly used in cost allocation in the transmission network. The transmission network price is calculated as:

$$P = \frac{TC}{\sum_{i=1}^{K} P_i} \tag{19}$$

where P_i (kW) is the magnitude of power signed in the contract for path *i*. Therefore, the network cost for customer *i*
is:

$$C_i = P \times P_i \tag{20}$$

4.7.2. Advantages and disadvantages

Similar to the postage stamp method, contract path is also a non-power-flow-based method. It is easy to calculate. The concept is easy to understand. The drawback is that the selected path may not be the actual power flow transported. The contract path is selected by the seller and the buyer without performing a power flow study to identify the path that is actually used in practice [53,62]. Neither the postage stamp nor contract path methods take the actual operating environment of the system into account.

4.7.3. Applicability to ICESs

ICESs do not have a transmission and distribution network. Energy is delivered to customers directly from the generation site. This is not the same with large power systems, for which a path can be selected for transporting energy from generation to customers at remote locations. This method cannot be applied to cost allocation in ICESs.

There is no selected path for transporting power in ICESs, however, it is possible to sign a contract with customers to determine the installed capacity of DERs. In a small-scale DERs based energy system, the installed capacity is usually calculated by following the rule that the annual energy generation should satisfy the annual energy consumption [98]. The contract path method can be modified as it allocates the total costs according to the individual requirements of DERs. Customers are required to consume energy within the generation capacity. Here is a brief introduction of the concept of contract capacity, further research is still required. For instance, investigating the impact of peak demand on the energy bills of each household.

4.8. Distance-based-MW-mile method

4.8.1. Approach

The distance based MW-mile method allocates the transmission network cost based on the magnitude of transacted power and geographical distance between seller and buyer [91,99]. The product of the magnitude of the transacted power and the distance it travels is called the MW-mile value. This method is a usage-based cost allocation method, charges are calculated based on the extent of use of the physical network [95]. The transmission network price is proportional to the MW-mile value and is calculated as:

$$P = \frac{TC}{\sum_{i=1}^{K} PX_i} \tag{21}$$

$$PX_i = L_i \times P_i \tag{22}$$

where PX_i (MW • mile) is MW-mile value, L_i (mile) is the geographical distance between seller and buyer of transaction *i*.

The transmission network cost for transaction *i* is:

$$C_i = P \times PX_i \tag{23}$$

4.8.2. Advantages and disadvantages

This method provides economic signals to short and long distance network users to make the best use of the existing transmission network system [91]. However, it is hard to show the relationship between the transacted power and the power flow transported [62].

4.8.3. Applicability to ICESs

Local community members are close to each other geographically and are connected with low voltage in the ICES. Therefore, the power transportation lines are so short that the distance can be neglected. The distance-based-MV-mile method is applicable in high voltage transmission networks, it is not suitable for the situation of ICESs.

4.9. Power-flow-based-MW-mile method

4.9.1. Approach

The power-flow-based-MW-mile method allocates the transmission network cost based on the magnitude of power flow [100,101]. It is a power flow based cost allocation method, the cost is recovered by power flow charges [62,95,102]. The transmission network price is calculated as:

$$P = \frac{TC}{\sum_{i=1}^{K} \sum_{j=1}^{M} c_j L_{i,j} P_{i,j}} \tag{24}$$

where K is the set of all transactions and M is the set of all circuits. c_j (€/MW-mile) is the cost of circuit *j* per MW per mile, $L_{i,j}$ (mile) is the length of circuit j of transaction i, $P_{i,j}$ (kW) is the power flow in circuit *j* caused by transaction *i*. The transmission network cost for transaction *i* is:

$$C_i = P \times \sum_{j=1}^{M} c_j L_{i,j} P_{i,j} \tag{25}$$

4.9.2. Advantages and disadvantages

This method takes into account the actual system operation conditions, it is able to send correct and efficient economic signals to the users. It helps promote rational future investment for network expansions and reinforcement [96]. The costs allocated to users are based on their actual usage of the transmission network. However, compared to the postage stamp method, this usage-based method is much more complicated and the payments are less predictable.

4.9.3. Applicability to ICESs

The power flows of households vary widely during the day, it is hard to measure their magnitude. The length of the circuit from generation to households is so short that it can be neglected. Even though this method takes into account the actual operation of the energy system, it is difficult to do these measurements in an ICES. This method is mainly used in high voltage transmission network cost allocation, it is not recommended to apply it to cost allocation in ICESs.

4.10. Coincident peak method

4.10.1. Approach

A coincident peak (CP) method allocates costs in proportion to its share of the system peak during the measured time cycle (for example, one year) [50,103]. It is usually used in transmission and distribution network cost allocation in the United States and the United Kingdom [104,105]. Accordingly, there are the 2-CP, 4-CP and 12-CP methods. The 2-CP method uses the average system peak demand in winter and summer as the system peak demand, and the average individual peak demand in winter and summer as the individual peak demand. The 4-CP uses the average demand in four seasons, and the 12-CP uses the average demand in twelve months as the peak demand. These methods show the time difference impact on the system peak instead of one single peak demand. With coincident peak pricing mechanisms, industrial consumers reduced their peak demand in response to the 1-CP and 4-CP, while the cost reduction of the 4-CP is much larger than the 1-CP [106], as it encourages demand response during multi-peak hours. The demand charge is calculated as:

$$P=\frac{TC}{\sum_{i=1}^{N} P_{CP\_i}} \tag{26}$$

where P_{CP_i} (kW) is peak demand of customer i occurring at the system peak hours. The cost allocated to customer i is:

$$C_i = P \times P_{PC\_i} \tag{27}$$

4.10.2. Advantages and disadvantages

A coincident peak method is cost-reflective, the costs reflect the individual's contribution to the system peak demand [60]. However, these methods ignore load information, such as load factor and energy consumption [83]. A coincident peak method is also more beneficial to those who have a higher load factor; even though their load demand does not fluctuate significantly, they are using the generation facilities most of the time.

4.10.3. Applicability to ICESs

This concept is similar to the concept of the postage stamp method. The required data are coincident peak demand of each household and the whole system. It is easy to get these data with the deployment of smart meters. It reflects the contribution of peak demand of each household to the whole system. For the 2-CP, 4-CP and 12-CP methods, they follow the same principles as the 1-CP, they can also be used in cost allocation in ICESs. They are more accurate when more time periods are taken into account.

4.11. Non-coincident peak method

4.11.1. Approach

A non-coincident peak method allocates costs in proportion to the sum of the individual peak demand, regardless of when it occurs during the measured period, which may not coincide with the system peak [50, 82]. It is based on the theory that the system could satisfy all the customers' maximum demand. The demand charge is calculated as:

$$P=\frac{TC}{\sum_{i=1}^{N} P_{NCP\_i}} \tag{28}$$

where P_{NCP_i} (kW) is the individual peak demand of customer i. The cost allocated to customer i is:

$$C_i = P \times P_{NCP\_i} \tag{29}$$

As with the CP methods, there are also a number of NCP methods: 2-NCP, 4-NCP, and 12-NCP, which are based on the same principle as NCP methods.

4.11.2. Advantages and disadvantages

Individual peak demand may not occur at the same time as the system peak demand, therefore, it may not reflect consumers' contribution to the system peak demand. It reflects how their individual peak demand influences their energy bill. But it still ignores detailed information about energy consumption.

4.11.3. Applicability to ICESs

The required data are the peak demand of each household. It is also easy to measure individual peak demand with the help of smart meters. A non-coincident peak method is easy to implement in cost allocation in ICESs. The 2-NCP, 4-NCP, and 12-NCP methods follow the same principles of the 1-NCP method, and they also can be applied in the case of ICESs.

4.12. Cost allocation based on the cost-causality principle method

4.12.1. Approach

Cost allocation based on the cost-causality principle method refers to allocating system costs to the agents or elements (also referred to as cost drivers) that cause them, thus giving a highly efficient signal [31,107]. This method is derived from the accounting approach, but it is more robust in that it follows the cost-causality principle. However, it is hard to determine the cost-causality cost function. This method can be used in cost allocation not only for the vertically integrated energy system, but also for separate activity. For instance, in Norway, the distribution network company charges household consumers an annual fixed charge, a demand charge and a variable energy rate [108]. Under this approach, there is no need to function the total cost into different activities. The cost-causality method based on the analysis of the cost-causality function is proposed in Ref. [20] for recovery of distribution costs. The reference network model is used as a tool for analyzing the cost-causality function, which is an optimization modeling tool that can be used to minimize the total network costs. The cost-causality function reflects the relationship between costs and their causes [20,31]. The cost-causality based method is studied in Ref. [103]; a nodal pricing method is used to recover loss costs and a coincident peak method is used to recover fixed network costs, taking time and location into account. According to the research in Refs. [50,81,82], in general, three steps are identified to allocate costs based on the cost-causality principle, namely: functionalization, classification, and allocation.

(1) Functionalization: this is the process of grouping assets and expenses into different operating functions: generation, transmission, distribution and supply. Generation costs are the expenses for energy generation and purchases. Transmission

network costs are associated with the expenses for building the transmission network for connecting generators and the distribution network. Distribution network costs are the expenses for building distribution networks for connecting the transmission network and customers. Supply-related costs are the expenses for providing services to end-users, including: meter, meter reading, billing, billing collection, and other customer-service-related activities.

(2) Classification: this is the process of separating the costs of operating functions to the different cost drivers that cause them [19, 81]. Cost drivers are the key factors that drive the total costs of the power system [31,107]. Cost drivers are selected according to two criteria: they should have a great impact on the system costs and they should be easy to measure. According to the study in Refs. [109–111], the commonly used cost drivers are: energy (kWh), capacity (kW) and customer service (customer number). The standard costing methods adopted by the United States utility companies are: fixed costs that are demand-related, and variable costs that are energy-related [51]. Demand-related costs include the costs of generation, transmission and a part of distribution network facilities. Energy-related costs include fuel costs, power purchase costs and plant maintenance expenses.

(3) Allocation: this is the process of allocating energy, demand and customer-service-related costs to different customer categories. In general, the customer categories include: industrial, commercial and residential customers according to the load characteristics. Traditionally, time difference is not taken into account, demand costs are allocated based on the peak demand, energy costs are allocated based on the quantity of energy produced and purchased, and customer costs are allocated based on the number of customers.

4.12.2. Advantages and disadvantages

The advantages of this method are obvious: costs are allocated based on the drivers that cause them. It is cost-reflective. It takes into consideration different activities, voltage levels and customer categories. The final tariff structure is detailed but also makes the allocation process much more complex. It is not easy to implement this method in practice as some costs are difficult to classify. It is not an easy task to classify the costs accurately.

4.12.3. Applicability to ICESs

The activities involved in ICESs are mainly generation and power supply, nearly all costs can be considered fixed, they do not vary with the energy generated. There is only one customer category: household residents are the end-users. The characteristics of an ICES simplify the process of this method. Based on the analysis above, fixed costs are usually attributed to capacity and customer service. It is easy to apply this method to cost allocation in ICESs. However, the generation capability of RESs is affected by weather conditions, energy generation is not always at the maximum. Even though investment, O&M costs are fixed in ICESs, energy generation varies. Modification is required to think about how to classify costs to the cost driver of energy instead of classifying fixed costs as demand-related. In addition, it is also worth investigating what the impact is of different percentages of energy costs and capacity costs on the consumption behavior of consumers and their energy bills.

4.13. Summary

Table 3 summarizes the main characteristics of the methods reviewed above. Each method is assessed according to its pricing components, time reflectiveness, location difference, applicable in ICESs and ease of application:

1. Pricing components include energy, capacity and customer service. Cost allocation based on the cost-causality principle method can be used for pricing all of these components, but the other methods can only be used for pricing one single component.
2. Time reflectiveness is an important characteristic in energy pricing, as load profile differs a lot during off-peak and peak hours. A time-reflective method can incentivize consumers to shift their peak demand to off-peak hours. In addition, the methods for pricing capacity also reflect the impact of peak demand on energy bills. It is also an effective way to reduce peak demand.
3. Location-based methods are usually used for pricing transmission networks. The characteristic is that tariffs differ according to the location in the network. This is especially useful for utility companies if the capacity of the network is not high enough to satisfy peak demand, or when the transport distance is so large that it entails significant losses.

Table 3
Summary of cost allocation methods.

Number	Method	Pricing components	Time reflective (Yes/No)	Location based (Yes/No)	Applicable in ICESs (Yes/No)	Ease of application	References
1	Flat energy pricing method	Energy	No	No	Yes	+ + +	[30,34,37,39,46]
2	Base and peak method	Energy	Yes	No	Yes	+ +	[50]
3	Marginal cost pricing method	Energy Capacity	Yes	No	No	–	[20,31,53–55]
4	Average and excess method	Capacity	No	No	Yes	+ +	[50,81–83]
5	Ramsey pricing method	Energy	Yes	Yes	No	–	[27,33,49,84–86]
6	Postage stamp method	Capacity	No	Yes	Yes	+ + +	[53,54,89–91]
7	Contract path method	Capacity	No	Yes	No	–	[53,54,92,94]
8	Distance-based-MW-mile method	Capacity	No	Yes	No	–	[53,54,64,91,99]
9	Power-flow-based-MV-mile method	Capacity	No	Yes	No	–	[53,90,100,101]
10	Coincident peak method	Capacity	No	No	Yes	+ + +	[50,81,103]
11	Non-coincident peak method	Capacity	No	No	Yes	+ + +	[21,50,81,82]
12	Cost allocation based on cost-causality principle method	Energy Capacity Customer service	No	No	Yes	+	[19,31,107]

+ stands for the level of ease, the more the easier. The classification is based on the number of charges, the less the easier.
- stands for null.

4. According to the analysis of the characteristics of each method, and considering the special characteristics of generation and cost structure of ICESs, the applicability of each method in cost allocation in ICESs is concluded. In the context of this research, applicability means if the method can be applied to cost allocation in ICESs directly. Some methods can also be applied in ICESs, while modifications are required.
5. Another aspect that may be interesting to see is how easy it is to apply the methods to cost allocation in ICESs. There is no consensus on the definition of ease, in this research, we use the number of pricing charges as the indicators to evaluate the ease of each method. The less the pricing charges, the ease it is to apply the method to allocate costs in ICESs.

A large part of the costs in ICESs are capital intensive, they do not vary with the amount of energy generated. Therefore, fixed charges are more relevant in terms of the cost structure. Energy generation is close to local communities, high voltage transmission network is not required in ICESs to transport power. Therefore, location-based methods, such as distance-based-MW-mile and power-flow-based-MW-mile methods, are not particularly relevant in ICESs. It is easy to measure the peak demand of individual households with smart meters, so, postage stamp, coincident peak, and non-coincident peak methods can be applied in cost allocation in ICESs, as they allocate costs based on the peak demand of each customer.

Energy consumption varies during the time of the day, low in the daytime and high in the evening hours. Time reflectiveness sends economic signals to customers to adjust their consumption behavior. During the sunny daytime or windy days, energy generation from local RESs (solar panels or wind turbines) is high, and the energy price could be low. During low generation hours, especially at night, generation is insufficient, peak demand occurs, and the energy price should be high to indicate to consumers that energy is sparse at that time. High energy consumption would incur high energy bills. Time reflectiveness is a very important indicator in assessing the performance of cost allocation methods. The methods that show time reflectiveness include the base and peak method, marginal cost pricing method, and Ramsey pricing method. However, the marginal cost pricing method and Ramsey pricing method are not recommended for use in cost allocation in ICESs, due to the fact that the marginal cost for RESs is zero, and an electricity price cannot be derived from the mathematical formulation of Ramsey pricing.

New insights can also be derived from these concepts based on the analysis of these methods, for example, energy pricing based on consumption levels is derived from the concept of average and excess method, allocating costs based on the individual requirement of the capacity of DERs. In summary, the methods used in large power systems provide a wide range of options in terms of charging energy and capacity to allocate costs in ICESs.

5. Discussion

The methods reviewed in this paper provide diverse options to allocate cost in ICESs, all derived from existing methods for tariff setting of utility companies. ICESs are a special organization compared to large power systems. It is still on the way of development. Besides cost allocation design and methods, ICESs still confront with many problems in the implementation of cost allocation in ICESs. Table 4 provides an overview of the main barriers and enablers for cost allocation in ICESs. In this section, we elaborate on these issues, their effects on cost allocation and possible solutions in detail.

5.1. Assessment framework

One problem is how to assess the performance of each cost allocation method. There are many options that can be used to allocate costs in

Table 4
Main barriers and enablers for cost allocation in ICESs.

	Barriers	Enablers
Economic aspects	1.There is no systematic framework on how to design cost allocation in ICESs.	1. Tariff design framework in large power systems provides a good example, including objectives, procedures, tariff structure and regulatory principles.
	2. There are no methods on how to allocate costs in ICESs	2. Cost allocation methods used in tariff design provide various options.
	3. Energy exchange is enabled in ICESs between local community members and ICESs. while there are no mechanisms on how the energy should be exchanged.	3. Periodic compensation, net energy exchange, community based P2P or full P2P mechanisms can be applied in ICESs to enable energy exchange between local community members and ICESs.
	4. The costs in ICESs are capital intensive, which are fixed, it is difficult to send incentives to customers for efficient energy usage.	4. It is possible to translate fixed costs to variable costs and formulate variable energy and capacity charges
	5. Due to the uncertainty of energy exchange price between an ICES and the grid, and the dependence of ICESs on the grid, off-grid and grid-connected ICESs have impacts on the cost structure of ICESs. It will affect the selection of cost allocation method.	5. The dependence on the grid of ICESs should be evaluated at the beginning of the project, and cost allocation should be made flexible in order to deal with the uncertain change of energy exchange price.
Social and management aspects	1. 'There is no assessment framework illustrating the performance of cost allocation methods, since there are many factors affecting their performance.	1. Multi-criteria decision-making method could be used as the assessment methodology.
	2. Cost allocation in ICESs should be designed in a socially acceptable manner, while what factors can contribute to social acceptance?	2. Regulatory principles in tariff design and social acceptance on renewable energy innovation could be adapted to conceptualize social acceptance in ICESs.
	3. The different formulation of ICESs (private vs joint vs community DERs) have impacts on the sustainable development of ICESs, since the costs are burdened by different parties.	3. Making contracts at the beginning of the project to ensure local community members remain in the community with a certain time.
	4. There are many stakeholders involved in ICESs with different preferences and objectives. It is hard to satisfy all their requirements at the same time, then the problem is how to ensure the long-term commitment of local community members.	4. Incentivizing local community members to be investors in ICESs and balancing their requirements with an appropriate cost allocation mechanism.
	5. There is no regulator in ICESs and no regulation to regulate the activity of cost allocation in ICESs.	5. Set up a community committee to collect opinions from local community members to help them make decisions based on the developed cost allocation framework. The activity of allocating costs can be managed by a community manager or an energy company.

ICESs. Each method has its own characteristics and local community members have different preferences. There is no one-size-fits-all solution that fulfills all requirements. It is important to develop an assessment framework to help the local community members to rank the options and select the one meeting their requirements. It, therefore, represents a decision-making problem under diverse and conflicting conditions [112, 113]. This issue can be addressed by applying the multi-criteria decision-making (MCDM) method to support decision-making [114,115]. According to the analysis of MCDM, relevant criteria are required to assess the performance of these cost allocation methods. The regulatory principles provide relevant criteria for assessing the cost allocation alternatives. However, most of these principles have a qualitative characteristic. It is not easy to give quantifiable outcomes, which increases the difficulty of the assessment. In addition, criteria are suggested to reflect social acceptance, which are required to be further developed and identified. The framework presented below may be applied to evaluate the performance of cost allocation methods for application in local communities.

In general, a widely used framework for the MCDM problem is summarized in Fig. 5. The first step is to establish an appropriate objective, it should cover all the main aspects of selecting cost allocation methods, which may include the objectives discussed in 3.6. The second step is to identify alternatives of cost allocation methods, as modifications are required for some methods reviewed in this paper to fit into the situation of ICESs. The next step is to define possible criteria to evaluate the performance of each cost allocation method. The selection of criteria should be associated with the objective of MCDM. In addition, it is of great importance to quantify the selected criteria, while trying not to destroy their original meaning. This is one of the most important steps in MCDM and the most challenging task. The criteria could be from many perspectives, for instance, technical, economic, environmental, and social criteria. The fourth step is to weigh the criteria based on the preferences of local community members. The weighting is used to show the relative importance and impact of the selected criteria in the MCDM problem. They have a great influence on the results of the performance of cost allocation methods. The final step is to rank the alternatives based on MCDM and select an appropriate method acceptable to the community. The optimal solution will be obtained by comparing the performance (values) of each alternative. This framework is a powerful tool to help select the desired cost allocation method for local communities.

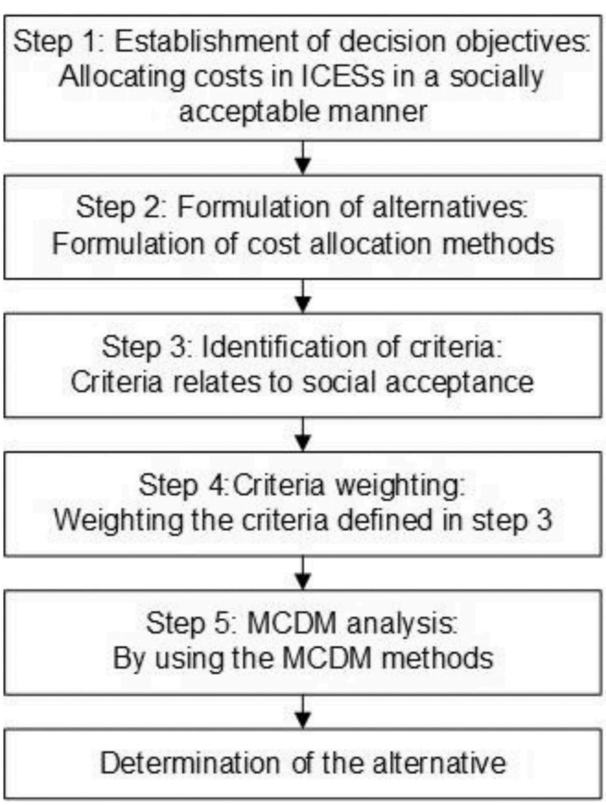

Fig. 5. A general framework for the MCDM problem.

5.2. Social acceptance

Social acceptance is critical in ICESs for the success of cost allocation in ICESs. As there is no regulator in the energy system, all decisions are made by the local community members themselves. Therefore, it is important that costs should be allocated in a socially acceptable manner. However, what does social acceptance mean in the case of an ICES? Does it mean local members feel the process of allocating costs is fair despite the results? Or does it mean local members feel the result is fair despite the process? Studies about social acceptance have been mainly focused on social acceptance of renewable energy innovations [116,117,118, 119,120]. They analyzed social acceptance from the perspective of distributive and procedural justice.

The study in Ref. [116] explores the application of procedural justice to community consultation by investigating if procedural justice can increase social acceptance of the outcome. It used an empirical research to study the social acceptance of a wind farm, and the results showed that a fair process does increase acceptance of the outcome. The research demonstrated that procedural justice has the potential to be a community consultation approach, which can help increase social acceptance of the outcome.

The concept of social acceptance of renewable energy innovation is introduced in Ref. [117], it indicated that social acceptance is the main challenge to achieve renewable energy innovation, especially on wind energy. The study explored the three aspects of social acceptance: socio-political, community, and market acceptance. In general, socio-political acceptance is associated with the acceptance by stakeholders and policy actors, and it has a close relationship with market and community acceptance. Community acceptance concerns with the acceptance by local community members and authorities. The factors that may influence community acceptance include distributive and procedural justice. Distributive justice focuses on a fair allocation of costs and benefits, and procedural justice concerns with the participation of relevant stakeholders and transparency of information. The focus of market acceptance is on investors, concerning their benefits. The three aspects of social acceptance interact with each other and have an influence on each other. The involvement of various stakeholders (investors, local community members, policy makers, and local authorities) affect political and financial decisions.

Social acceptance issues of energy infrastructure projects (transmission lines and wind energy) were investigated in Ref. [118], which include frameworks, participation, and communication strategies. The study discussed how they lay down the dimension of social acceptance in the context of energy infrastructure projects and concluded that community acceptance is the most critical one in the research. The study analyzed the problems and benefits based on an empirical-qualitative study. It collected the viewpoints, attitudes, and positions from experts, stakeholders, citizens, environmental organizations, national government, and local authorities. This research fostered a better understanding of the main challenges inherent in the social acceptance of energy infrastructure projects.

The influence of stakeholders on the development of community renewable energy projects and how they are influenced by the outcome were presented in Ref. [119], by interviews. The results showed that key stakeholders would support or hinder the project by looking at the potential benefits or harms it may have in the implementation phase. Moreover, once a community renewable energy project is established, stakeholders may change their position as supporting or hindering by the actual influence of the outcome has on them: benefiting or harming. It is concluded that stakeholders have impacts on the outcome of the project, and the outcome also influences the decision of stakeholders as well. Therefore, both procedural and distributive justice are indispensable in the study of social acceptance.

The research in Ref. [120] studied how community benefits affect local support for wind farm developments by using questionnaire surveys. The results showed that community benefits could increase the social acceptance of an offshore wind farm and might alter individuals' perceptions of procedural and distributive justice.

These works analyzed above provide fundamentals to further investigate social acceptance in cost allocation in ICESs. They illustrated the three key dimensions of social acceptance and the key factors influencing acceptance in each dimension. Renewable energy innovations have the special characteristic that they are relatively on a small scale, which is similar to the case of ICESs with small-scale DERs. Furthermore, there are various stakeholders involved in the project. It is easy to translate these concepts into the context of cost allocation in ICESs. Considering the characteristics of ICESs, it can be concluded that community acceptance is far more important than socio-political and market acceptance, as it focuses on the acceptance by local community stakeholders, especially the viewpoints of local residents on the results of cost allocation. The two aspects affecting community acceptance are essential elements in assessing social acceptance. Procedural justice concerns with a fair process of cost allocation and distributive justice focuses on a fair result. According to the analysis, it is possible to define the criteria (or indicators) to measure fairness from the perspective of procedural justice qualitatively and distributive justice quantitatively. It is then essential to define the indicators that affect procedural and distributive justice. For instance, the extent to which the stakeholders are provided with sufficient information may serve as an indicator for transparency and the involvement of local community members in the decision-making process. Furthermore, the indicator of cost reflectiveness can be used to assess distributive justice, since it reflects whether the local community members pay what they should pay. The two perspectives of procedural and distributive justice should be further developed and defined in order to achieve socially acceptable cost allocation in ICESs. It is the ultimate goal and the determining factor that affects the success of cost allocation in ICESs.

5.3. Energy exchange schemes

Energy exchange schemes in the local community are supportive mechanisms for allocating costs in an ICES. Consumers only consume energy in the ICES, they buy electricity from the community. However, prosumers not only consume energy but also produce it. The question is, what is the proper mechanism of energy exchange inside an ICES. It is of great challenge, while it must be solved in order to achieve a fair cost allocation in ICESs. This discussion proposes several possible options for energy exchange inside ICESs.

The first option is to give prosumers a periodic compensation for energy supply to the community, comparable to the allowed revenues for utility companies in a large power system. Prosumers are then charged for their electricity consumption based on the tariffs adopted in the community. The potential problem caused by this option is that the compensation is not the exact benefit they get in actual, which may be unfair to local community members. Prosumers may get more or less than the value of the amount of energy they contribute to the energy system. Consumers will burden the extra part if prosumers get more than they should get, and consumers will benefit from this if prosumers get less than they should get. It is challenging to set appropriate compensation in ICESs.

The second option involved, considers only the net exchange between each member and the community being charged. The problem is that prosumers may take free-riding under a net exchange scheme if they pay at a lower price or get benefits for the net energy exchange. Generally speaking, prosumers have surplus energy during the daytime and need energy during night hours. The energy costs during night hours are high. However, the total costs of the energy system are fixed, consumers will burden the costs that should be paid by prosumers. It will lead to an unfair cost allocation, which is not desirable. Therefore, it is essential to set an appropriate tariff for prosumers under a net energy exchange scheme to balance the different energy costs in different hours.

The third option is that prosumers sell their surplus energy to the community at one price and buy deficit energy from the community at another price. This scheme is similar to the concept of community-based peer-to-peer (P2P) energy trading as illustrated in Refs. [121,122]. Local community members trade through ICESs, in this case, an ICES plays a role as an aggregator. The energy trading activity can be managed by a community manager or an external energy company. The problem is how to set the trading tariff to make sure prosumers get the benefits they should get. If the selling price is lower than the price of selling to the grid directly, prosumers will not be willing to sell it in the community. If the buying price is higher than the price buying from the grid, prosumers will not be willing to buy it in the community. Finally, this will lead to prosumers leaving the community.

The fourth option is a full P2P energy exchange mechanism [121]. Bilateral contracts are made between two parties to exchange energy at an agreed price [123], it is consumers (buyers) and prosumers (sellers) in ICESs. It allows prosumers to sell their energy to consumers directly. The problem is similar to the third option, how to set a fair energy exchange price to balance the benefits between prosumers and consumers in ICESs.

The four options provide possible energy exchange schemes in ICESs, and they affect the benefits and costs received and paid by prosumers and consumers. They have the same problem that how to set the energy exchange price to make sure prosumers get the benefits they should get and consumers pay the costs they should pay. It is unsure to which extent it affects the results of cost allocation. Therefore, it is recommended to have a case study with quantitative results to show how each one influences the costs and benefits allocated to each local community member. In addition, it should take the opinions of local stakeholders into account to see if they think the option is socially acceptable by them. It is important to get consent from local stakeholders. Local policy conditions should also be taken into account when implementing the energy exchange mechanism in ICESs. Overall, a proper energy exchange mechanism should be designed for a successful implementation of cost allocation in ICESs.

5.4. Incentives for efficient energy usage

Giving energy efficiency incentives to ICES members is challenging since the costs of an ICES are highly capex-related, i.e., they do not vary with energy generation. Some of the cost allocation methods are used to allocate fixed costs. These do reflect cost structure, for example, the coincident peak method, but they do not give proper incentives in the long-term. While some other methods give proper incentives, for example, ToU energy pricing, they do not reflect the underlying cost structure. Consumers can adjust their consumption behaviors under a variable tariff, which can then put cost recovery at stake. Considering the characteristics of load profiles, they are influenced by many factors, such as the time of day, energy consumption, and peak demand. In order to provide economic signals to customers, it is essential to translate the fixed costs into a variable tariff. For instance, the costs can be classified between energy-related and capacity-related. For energy-related costs, the methods used for pricing energy components and reflecting time difference can be adopted. For capacity-related costs, the methods used for pricing peak demand can be adopted. By doing so, the billing structure includes variable energy and fixed capacity prices. These are economic signals provided to customers indicating that their energy bills are determined both by their energy consumption at various times of the day and by peak demand. In future work, it is essential that a scheme be adopted that can translate the costs into variable tariffs, in order to give proper incentives to customers to remain in the ICES.

5.5. Off-grid vs grid-connected ICESs

ICESs can be operated in both off-grid and grid-connected modes, which impacts the cost allocation mechanism in ICESs. The community achieves self-sufficiency by operating in off-grid mode. There is no energy exchange between the ICES and the grid at any moment. All the costs incurred are inside the community. External factors have no impact on the cost structure of the energy system. Almost all the costs in ICESs are fixed. While there is energy exchange inside ICESs, the costs could be variable or fixed, which depends on the energy exchange mechanism taken.

In grid-connected operation mode, an ICES acts like an aggregator, it exchanges energy with the grid for the whole community. The problem would be how to define the energy exchange mechanism between the ICES and the grid and what the impacts are on cost allocation in ICESs and on the grid. Generation in ICESs mostly takes place during the daytime, and generally speaking, surplus energy is generated during this time. The surplus energy is sold to the grid, and the community can get benefits from this. However, the grid needs extra investment in the infrastructure to accept energy injection from ICESs, which increases system capital costs. During night hours, there is little or almost no generation. The system will purchase energy from the grid, and the community pays for this. These are also the peak consumption hours for the grid. This would therefore cause congestion or high generation costs for the grid. Therefore, grid-connected ICESs have impacts on the grid in terms of system operation and costs. In turn, grid-connected ICESs adds more cost items to the cost structure, such as grid-connection fee, service cost, and energy trading costs. Normally, grid-connection fees and service costs are fixed, which does not have much impact on the cost structure. However, energy trading costs vary with the amount of energy traded. Its impacts on cost allocation in ICESs are determined by the proportion of the costs take in the total costs.

If an ICES is largely dependent on the grid, the amount of energy traded is substantial, and the energy trading costs would represent a large proportion. If an ICES is aimed to achieve self-sufficiency, only trades with the grid when necessary, then the energy trading costs are negligible. While it needs to take the energy exchange price into account, if the energy price is very high, even though the amount of energy traded is not that much, it still has a large impact on the cost structure of ICESs. The change of cost structure impacts the selection of cost allocation methods and the economic signals provided to the local community members. In summary, the dependence of ICESs on the gird and energy exchange price should be taken into account in the selection of cost allocation methods for grid-connected ICESs.

5.6. Private vs joint vs community installation of DERs

There are three types of ICES formulation: individual DERs, joint DERs, and community DERSs, each of which has an impact on cost structure, on the selection of cost allocation methods, and on the stability of the ICES. Individual households are allowed to invest in DERs in an ICES. They are allowed to exchange energy within the community. In the case of ICESs with private installation, they pay for the costs of DERs themselves. They sell surplus energy to the community and also buy deficit energy from the community. Consumers only buy electricity within the community.

Costs are mainly caused by energy exchanges. The cost structure may be fixed or variable. It depends on the energy exchange scheme. This formulation is much more stable, as the investment of DERs is high and prosumers are bearing the risk for themselves. In the case of joint installation, some households invest in their own DERs, while at the same time, the installation of DERs also takes place at the community level. The costs consist of capital investment of community DERs and energy exchange costs. In the case of community installation of DERs, the costs are mainly capital investment, with a small portion of energy exchange costs. The cost structure of the two latter formulations is similar, both with capital investment and energy exchange costs. The two latter formulations are not as stable as the first one, as investors are bearing the investment risk. Costs will be re-allocated if some members leave the community, then the remaining members will pay more, especially for the fixed investment cost. Otherwise, cost recovery is at stake. The formulation of the ICES affects cost structures and the stable development of the ICES. Under this situation, some agreements should be made with the members, for example, by signing contracts with them to make sure they stay in the community for at least some years. Proper strategies should be made at the beginning of the project considering the formulation of the ICES to ensure cost recovery and stable development of ICESs in the long-term.

5.7. Long-term commitment of local community members

The long-term commitment of local community members affects the successful implementation and long-term development of the ICES. In this section, we will discuss the factors affecting the long-term commitment of local members, considering the preferences of various stakeholders. The stakeholders involved in ICESs are local community members and investors. Local community members can invest in DERs, and they can also provide financial funds. Investors care about whether their investments can be fully recovered by using the selected method. Therefore, local members who are also investors are more willing to stay in the ICES; they want to recoup their investment. This factor should be taken into consideration at the start of the project when looking for the required investment to build the energy system. The preferences of local community members are generally divided into three main categories. The first one is where customers do not care much about the energy costs, and they would like to consume green energy without CO_2 emissions. It is easy to satisfy this requirement since energy generation in an ICES is mainly from DERs. The second one is where customers care about energy costs; they may compare the energy costs in the ICES to those from the grid. It is expected that the costs allocated to customers in an ICES are not higher than those from the grid. In that situation, customers would still like to remain in the ICES. Another possible scenario is that consumers who care about CO_2 emissions are paying more than those who care about energy costs, as long as they agree on this and feel it is fair. Otherwise, customers would withdraw from the ICES because of the higher energy bills. This may lead to a circle of decline: remaining members are fewer, leading to others leaving as well. The third preference focuses on fairness. It refers to a situation in which costs are allocated according to the drivers that cause them. For example, customers with higher peak demand should pay more. However, some of their preferences conflict with each other, for instance, cost recovery and fairness. In order to ensure a fair allocation of costs, sometimes it is not possible to ensure cost recovery. For example, local members perceive it as fair when the costs are allocated to them based on the cost causality principle. This would include variable energy price, while cost recovery is at stake in this scenario. It is not easy to fulfill both of the preferences at the same time. Therefore, the selected cost allocation mechanism should provide proper incentives to ensure that the preferences of all the stakeholders are satisfied and to promote the long-term commitment of the local members. The decision should be made by both parties.

5.8. Community committee

There is no regulator in an ICES, and no public institutions are involved. Cost allocation is based on private contracts. Therefore, the apparent problem would be (1) Who will define the cost allocation approach? (2) Will the consumers agree on the selected cost allocation method? (3) Who will draw up the details of the private contract?

(4) Who will sign the contracts with consumers? (5) How to ensure

every local member sticks to it? These problems complicate the implementation of cost allocation in ICESs. They must be solved at the beginning of the project. A possible solution is to set up a community committee. They represent the local community members. They collect opinions and questions from local community members. They are responsible for drawing up rules and principles to regulate cost allocation in the ICES. They select cost allocation methods that take into account all the benefits of stakeholders in the ICES. They are also in charge of signing contracts with local community members. For system operation and cost allocation, they can be managed by specialists or an energy company.

6. Conclusion and future work

6.1. Conclusion

ICESs provide a platform for integrating local DERs and communities. Cost allocation in ICESs is the key factor that affects the success of ICESs. It is a rather new topic, and not many studies have been carried out on this issue. This paper presents a brief overview of the key issues included in tariff design in large power systems and a comprehensive review of cost allocation methods. These cost allocation methods can be adapted for application in ICESs. This review paper also identified the main challenges that must be overcome in the process of cost allocation in ICESs and presented possible solutions. It is expected that a local community energy market will emerge when appropriate cost allocation in ICESs is available.

6.2. Future work

A tailored cost allocation mechanism in an ICES is still required due to the difference between large power systems and ICESs. ICESs are more focused on the involvement of local communities, so cost allocation should be carried out in such a way that it contributes to social acceptance in local communities. The next step for future research could focus on how to achieve cost allocation in ICESs in a socially acceptable manner. This work could include (1) development of the criteria for social acceptance, such as procedural and distributive justice mentioned in some renewable energy innovation research work, both qualitatively and quantitatively, (2) development of cost allocation methods, such as time-of-generation pricing, which takes the generation characteristic of DERs into account (3) performance assessment of cost allocation methods, this can help the local community members to select a method that satisfies their preferences.

CRediT author contribution statement

Na Li: Conceptualization, Methodology, Investigation, Writing – original draft, Writing – review & editing, Visualization. Rudi A. Hakvoort: Conceptualization, Supervision, Writing – review & editing. Zofia Lukszo: Supervision, Writing – review & editing.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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