Cost Allocation in Integrated Community Energy Systems

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Dissertation

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Science is a wonderful thing
if one does not have to earn one's living at it.

Albert Einstein

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Introduction and problem statement

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 CO_2 emission reduction. Integrated community energy systems (ICESs) emerge in the development of local energy systems by integrating local distributed energy resources (DERs) and local communities. Local community members are actively involved in the planning, development, and administration of the energy system as well as the allocation of its costs and benefits.

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. A well-designed cost allocation contributes to the successful implementation in the short-term and sustainable development of ICESs in the long-term. In large power systems, the regulator makes decisions on tariff design according to the regulatory principles. However, no regulators are dealing with these issues in ICESs. The local community itself needs to agree on the cost allocation method themselves. It, therefore, requires that the costs are allocated in a socially acceptable manner. In order to fill in the research gap, the main research question addressed in this thesis was:

How to design cost allocation in an ICES in a socially acceptable manner?

This question was answered by first reviewing cost allocation in tariff design, including the objectives, regulatory procedures, tariff structure design, regulatory principles and the widely used cost allocation methods. After that, an extensive discussion of how these concepts and methods can be applied in the context of cost allocation in ICESs was conducted. Based on this, a systematic framework was proposed in order to ensure a successful implementation of cost allocation design in ICESs.

Cost allocation framework

Cost allocation in ICESs is a rather new topic, there is no guidance on how to do it in a systematic manner. This thesis presented a systematic framework for allocating costs in ICESs learning from cost allocation in electricity tariff design. It clearly defines the objectives, procedures, and required components for allocating costs in a socially acceptable manner. Ten cost allocation methods that are applicable in the context of cost allocation in an ICES were derived and formulated mathematically to show their underlying principles.

Performance assessment of cost allocation methods

Each cost allocation method has its own characteristics and may perform differently. It is necessary to assess their performance in order to distinguish between them. In this thesis, two criteria: cost reflectiveness and predictability are proposed to evaluate the performance of the ten cost allocation methods. Cost reflectiveness is used to gain insights into how well the costs are allocated and cost predictability is used to show how the energy costs change in the long-term. For this purpose, a case study with 100 households is used in the model to investigate the performance of the ten cost allocation methods. The results showed that energy-based methods perform better compared to other methods. In order to further identify the effectiveness of the methods and how they perform in terms of the two criteria, a sensitivity and a robustness analysis are conducted. The sensitivity was conducted by investigating the changes in the number of consumers in the community.

The results showed that the number of consumers has little or no influence on the performance of the ten cost allocation methods in terms of cost reflectiveness and predictability. The robustness analysis was conducted by investigating the penetration of prosumers in the ICES. The findings concluded that the increasing prosumer penetration has a positive effect on the performance of the ten methods in terms of the two criteria in the event of changes in the number of local community members and prosumers. The two analyses also presented that the energy-based allocation methods can retain their merits in respect of the two criteria. The comprehensive analysis provides a better understanding of the performance of the ten cost allocation methods considered in this thesis.

Social acceptance analysis

One of the novel aspects of ICESs lies in the integration of local community members. They play an important role in the energy system by actively involving in the planning, development, and administration of the energy system as well as the allocation of its costs and benefit. Local community members are encouraged to participate in the decision-making process. They may have various preferences towards cost allocation. The selected cost allocation method should satisfy the requirements and preferences of local community members.

Furthermore, no regulators are involved in ICESs, the community itself needs to agree on the cost allocation method themselves. It, therefore, requires that the selected cost allocation method be socially acceptable to local stakeholders. In this thesis, social acceptance is conceptualized from the perspective of procedural and distributive justice to make sure both the process and the results of cost allocation are fair and socially acceptable to local community members. Furthermore, local community members with similar backgrounds and interests may have similar or the same preference over the criteria. Therefore, they can be classified into several groups according to their major preferences. It, therefore, stands for a multi-group, multi-criteria, and decision-making problem. Here we proposed a multi-group multi-criteria decision-making approach to support the local community member in

selecting a socially acceptable cost allocation method.

A simulation was also conducted in order to understand the decision-making tool developed in this thesis. The local community is categorized into different decision-making groups considering the differences in their major preferences. Seven decision-making groups are considered in this study, and their major preferences vary from fairness, cost reflectiveness to stability and any combination of them. The numerical results show that time-of-use pricing is the best solution for the seven decision-making groups considered in this research. In addition, an analysis with the changes in the weights of the decision-making groups was conducted to see how this would influence the selection of cost allocation method. The results indicated that the changes in the number of local community members in different decision-making groups influences the selection of best solutions.

Conclusions

This thesis presents a practical solution for allocating costs in ICESs in a socially acceptable manner. A systematic framework was formulated, possible cost allocation methods were proposed, and a decision-making tool was developed in the research in order to ensure a successful implementation of cost allocation design in ICESs. The methodology developed in this thesis can be applied to any local community energy system. The obtained results can be used by decision-makers to help them in the decision-making process. A successful cost allocation will definitely contribute to the implementation of ICESs, thus contributing to the energy transition.

Samenvatting

Introductie en probleemstelling

Door de groeiende zorgen in de wereld over de uitputting van fossiele energiebronnen en de bescherming van het milieu, wordt de transitie naar duurzame energiebronnen, een efficiënter energiegebruik en het verminderen van de CO_2 uitstoot steeds belangrijker. De ontwikkeling van lokale energiesystemen leidt tot de opkomst van geïntegreerde gemeenschappelijke lokale energiesystemen waarin decentrale elektriciteitsproductie in de lokale gemeenschap wordt ontwikkeld. De leden van deze lokale energiegemeenschappen zijn actief betrokken in het plannen, ontwikkelen en bedrijfsvoeren van het energiesysteem en verdelen onderling de kosten en baten.

In theorie moeten de kosten worden betaald door de betreffende energiegebruiker(s). De baten zouden moeten gaan naar de investeerders. Een goede kostenverdeling draagt bij aan een succesvolle implementatie op de korte termijn en een duurzame ontwikkeling van lokale energiegemeenstappen op de lange termijn. In grote energiesystemen worden de tarieven vastgesteld door een door de overheid aangestelde toezichthouder en verankerd in regelgeving. Maar in lokale geïntegreerde gemeenschappelijke lokale energiesystemen zijn deze er niet. Lokale gemeenschappen moeten dus onderling tot een goede kostenverdeling komen. Het is daarbij belangrijk dat de kosten worden verdeeld op een maatschappelijk acceptabele wijze.

In de wetenschappelijke literatuur is hierover nog weinig gepubliceerd. Om dit gat te dichten heeft dit proefschrift de volgende hoofdvraag:

Hoe kunnen de kosten in een geïntegreerd gemeenschappelijk energiesysteem op een sociaal-maatschappelijk geaccepteerde wijze worden verdeeld?

De vraag wordt beantwoord door allereerst te kijken naar hoe elektriciteitstarieven worden bepaald in het grote energiesysteem. In de analyse worden onder andere de doelen, de regelgeving, de structuur van de tarieven en de gebruikelijk gehanteerde kostenverdeling meegenomen. Daarna wordt uitgebreid besproken hoe deze concepten en kostenverdelingsmethodes kunnen worden toegepast in de context van geïntegreerde gemeenschappelijke energiesystemen. Aan de hand daarvan wordt een systematisch kader opgesteld om tot een succesvolle kostenverdeling binnen geïntegreerde gemeenschappelijke lokale energiesystemen te komen.

Kader voor kostenverdeling

De kostenverdeling binnen geïntegreerde gemeenschappelijke lokale energiesystemen is een nieuw onderwerp. Er zijn nog geen kaders voor hoe dit systematisch kan worden geadresseerd. In dit proefschrift wordt een systematisch kader gepresenteerd voor de kostenverdeling binnen geïntegreerde gemeenschappelijke lokale energiesystemen die is afgeleid van en gebaseerd op de tariefvaststelling in grootschalige energiesystemen. Het kader definieert duidelijk de doelen, de procedures en nodige componenten voor een sociaal-maatschappelijk geaccepteerde kostenverdeling. Er zijn tien verschillende methodes voor kostenallocatie onderzocht, die alle toepasbaar zijn voor de kostenverdeling in geïntegreerde gemeenschappelijke energiesystemen. Deze allocatiemethoden zijn wiskundig geformuleerd om de onderliggende principes te verduidelijken.

Beoordeling van de verschillende kostenverdelingsmethodes

De verschillende methodes voor kostenverdeling hebben elk hun karakteristieken en zullen daardoor anders presteren. Het is belangrijk om dit uit te zoeken, zodat de verschillen tussen de tien methodes duidelijk worden. In dit proefschrift zijn de kostenverdelingsmethodes met name geëvalueerd op twee criteria: kostenreflectiviteit en voorspelbaarheid. Door te kijken naar kostenreflectiviteit is inzicht vergaard in hoe de kosten worden verdeeld. De voorspelbaarheid geeft inzicht in hoe de prijzen in de energiesector veranderen in de loop der jaren. Hiervoor is een model gebruikt waarin de verschillende kostenverdelingsmethodes zijn geanalyseerd voor een casus van 100 huishoudens. Uit de resultaten blijkt dat de verdelingsmethodes op basis van energie beter presteren dan andere kostenverdelingsmethodes.

Een gevoeligheids- en robuustheidsanalyse is uitgevoerd om de effectiviteit van de methoden te beoordelen en hoe deze presteren op de twee genoemde criteria. De gevoeligheidsanalyse is gedaan door het aantal afnemers in het energiesysteem te veranderen. Hieruit blijkt dat het aantal afnemers bijna geen invloed heeft op de prestatie van de tien kostenverdelingsmethodes wat betreft de kostenreflectiviteit en voorspelbaarheid. De robuustheid is geanalyseerd door te kijken naar het aantal prosumenten in de geïntegreerde gemeenschappelijke lokale energiesystemen. Geconcludeerd kan worden dat een hoger aandeel prosumenten een positief effect heeft op de prestatie van de tien verschillende kostenverdelingsmethodes, gelet op de twee genoemde beoordelingscriteria. Daarnaast blijkt uit de uitgevoerde analyses dat de kostenverdeling op basis van energie positief blijft scoren met betrekking tot de twee genoemde criteria.

De uitgevoerde analyse biedt daarmee duidelijk inzicht in de werking en prestatie van de tien kostenverdelingsmethodes die in dit proefschrift worden behandeld.

Analyse van de maatschappelijk/sociale acceptatie

Een belangrijk aspect bij geïntegreerde gemeenschappelijke lokale energiesystemen is de betrokkenheid van een ieder in de lokale gemeenschap. De gebruikers spelen een belangrijke rol in het energiesysteem door zowel actief betrokken te zijn bij de planning, de ontwikkeling en het bedrijfsvoeren van het energiesysteem, alsmede de wijze waarop de kosten en baten worden verdeeld. De lokale afnemers worden juist gestimuleerd om mee te beslissen. De gekozen kostenverdelingsmethode moet voldoen aan de eisen en voorkeuren van de lokale gemeenschap. Hierbij kan iedereen verschillende voorkeuren hebben wat betreft de kostenverdeling.

Daarnaast zijn er geen toezichthouders die bepalen hoe de kostenverdeling moet plaatsvinden binnen geïntegreerde gemeenschappelijke lokale energiesystemen. De lokale gemeenschap moet hierover dus zelf onderling overeenstemming zien te bereiken. Daarom is het van belang dat de gekozen kostenverdelingsmethode sociaal aanvaardbaar is voor lokale belanghebbenden. In dit proefschrift is de maatschappelijke acceptatie bekeken vanuit de beginselen van de procedurele en distributieve rechtvaardigheid om ervoor te zorgen dat zowel het proces als het resultaat van de kostenverdelingsmethode eerlijk en sociaal aanvaardbaar zijn voor iedereen uit de lokale gemeenschap. Leden uit een lokale gemeenschap met een vergelijkbare achtergrond en interesses kunnen dezelfde voorkeuren hebben. Er zijn daarom verschillende clusters gemaakt voor groepen mensen gebaseerd op hun belangrijkste voorkeuren. Het gaat daarom om een 'multigroeps multicriteria' besluitvormingsprobleem. In dit proefschrift is een multigroeps multicriteria besluitvorming aanpak voorgesteld om de lokale gemeenschap te ondersteunen in het kiezen van een sociaal geaccepteerde kostenverdelingsmethode.

Met de ontwikkelde besluitvormingsaanpak is een simulatie gedaan met als doel de aanpak te evalueren. De lokale gemeenschap is hiervoor onderverdeeld in verschillende groepen op basis van hun belangrijkste voorkeuren. De belangrijkste voorkeuren variëren van eerlijkheid en kostenreflectiviteit tot stabiliteit, en een combinatie van deze aspecten. Dit resulteert in zeven verschillende groepen. De numerieke resultaten laten zien dat een kostenverdelingsmethode op basis van 'tijdstip-van-gebruik' de beste oplossing biedt. Ook is er een analyse gedaan naar de invloed van grootte van de verschillende groepen op de keuze van de kostenverdelingsmethode. Uit de resultaten blijkt dat een verandering in het aantal mensen binnen een van de genoemde groepen de uiteindelijke selectie van de beste oplossing kan beïnvloeden.

Conclusies

Dit proefschrift biedt een praktische oplossing voor een sociaal geaccepteerde kostenverdeling binnen geïntegreerde lokale energiesystemen. Er is een systematisch kader opgesteld, mogelijke kostenverdelingsmethodes zijn uitgewerkt en er wordt een aanpak voorgesteld voor de lokale besluitvorming om te komen tot een succesvolle kostenverdeling in een geïntegreerd gemeenschappelijk lokaal energiesysteem. De ontwikkelde methode in dit proefschrift kan in principe in elk lokaal energiesysteem worden toegepast. De verkregen resultaten kunnen worden gebruikt om beslissers te helpen met het besluitvormingsproces. Een succesvolle kostenverdeling zal namelijk bijdragen aan de implementatie van geïntegreerde gemeenschappelijke lokale energiesystemen, en daardoor indirect ook aan de energietransitie.

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Last but not least, dear readers, no matter who you are and where you come from, when you open this thesis, I do believe we have the same passion for contributing to a sustainable and green world. I hope you will read this thesis with pleasure.

Na Li
Delft, October, 2021

1

Introduction

To love and be loved is to feel the sun from both sides.

David Viscott

This chapter provides general background information on the thesis. It mainly introduces the research topics, and defines its objectives and scope. It also gives a general overview of the chapter's content for the rest of the thesis.

1.1. Integrated community energy systems

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 CO_2 emission reduction [2, 3]. 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% compared to 1990 levels [4, 5], and reduce at least 55% greenhouse gas emissions [6]. The 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 [7, 8]. DERs provide flexibility not only in terms of energy generation and consumption but also in the reform of energy systems by making them decentralized [9]. Local communities play a key role in the transition of energy systems by implementing DERs and changing their roles from consumers to prosumers [7, 8]. 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 [10].

According to the Clean Energy for All Europeans package [11], energy communities have the potential to change the local landscape in the energy transition, by promoting local energy generation, consumption, and trading, thus contributing to a successful energy transition [12]. Energy communities are a group of citizens who invest in local community energy systems collectively with non-commercial economic aims, such as environmental and social benefits, instead of financial profits [13]. Local citizens have ownership of the community energy systems, and they actively participate in local activities to take effective control of the energy systems [14, 15]. In the EU context, energy communities are mostly formulated as energy cooperatives [14]. Currently, 1900 energy cooperatives are formulated across the EU (until 2021), which are members of the European federation of citizen energy cooperatives (REScoop.eu), serving more than one million European citizens [16]. Several terms are frequently used in recent publications to describe energy communities, such as citizen energy communities [17], or renewable energy communities [14].

Integrated community energy systems (ICESs) are also a form of energy communities, which focus on the integration of local communities and local DERs [18, 19]. According to Koirala (2017), "ICESs are a comprehensive and integrated approach for local energy systems where communities can take complete control of their energy system and capture all the benefits of different energy system integration options" [19]. ICESs utilize the technical values of community microgrids and the social and economic values of integrated energy systems to create systems that are robust, reliable, and secure [20]. ICESs emphasize the engagement of local community members to participate in the decision-making process, on such matters as making investments in community DERs and selecting a socially acceptable cost allocation method, so that they take full control of the energy system [18]. Individual households are the basic units of local communities; they can choose whether or not to invest in an individual DER. In doing so, they are changing their roles from being consumers to prosumers thanks to local generation, demand response, and energy efficiency measures. They are interconnected and can also consume or share energy within an ICES, once they agree to join.

ICESs focus on the local landscape by managing local energy generation, delivery, exchange to meet local energy demand. 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 [20–22]. 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. Similar to any local energy system, ICESs could work in off-grid operation mode to achieve self-sufficiency and grid-connected operation mode to get support from large power systems [1]. 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.

One of the novel aspects of ICESs lies in their ability to enable community control of energy generation and consumption, which is a big step forward in social innovation in the management of energy systems. Various actors can involve themselves in ICESs, with different interests. Local community members can generate and consume affordable and green energy. They are also offered the opportunity to become investors and have the right to make decisions. External investors can invest in community DERs, too, to pursue profits. Energy service companies make profits by providing related services, such as energy efficiency improvement, system operation, and the management of local generation and delivery. A strong sense of community is essential for an ICES, since local community members are involved in the planning, development, and administration of the energy system as well as the allocation of its costs and benefits [23, 24]. According to [25], local communities are distinguished between locality and interests. In this thesis, locality and interest are integrated that local communities are located close to each other geographically, and they have a common interest to contribute to energy transition and invest in local DERs either individually or collectively. Furthermore, they are willing to form a cooperative in a local project.

Earlier studies on ICESs have mostly concentrated on technical aspects, such as hierarchical management [26], optimal scheduling, and dispatching with the objective to minimize operational costs [21, 27, 28]. The available tools for optimization planning and analysis of ICESs are comprehensively reviewed in [20]. The study in [29] presents an assessment framework for the value of ICESs in terms of costs and benefits for local communities. Another assessment framework is presented in [1], to evaluate the value of ICESs in terms of total energy costs and CO_2 emissions in grid-connected and off-grid operation modes. These works thus focus on technical optimization problems driven by economic incentives to reduce operation and energy costs, and environmental concerns to reduce CO_2 emissions.

The review in [18] provides a good overview of the key issues and trends shaping the development of ICESs. One of those key issues that requires further study is the fair allocation of costs and benefits among local stakeholders. Costs should be allocated to those who cause them, and benefits should accrue to those who make the investments. However, the work associated with cost allocation in the application of ICESs has not been studied in the existing research. It will therefore be of great value to investigate this aspect in depth in order to facilitate the successful implementation of ICESs in the short-term, as well as to ensure their long-term development. A fair cost and benefit allocation in ICESs is the key issue that determines the success of ICESs [22]. 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. Cost allocation in community energy systems

Cost allocation in integrated community energy systems is a rather new topic, which is increasingly gaining attention in recent years following the energy transition trend. In this section, we did a literature review on this topic to summarize the current situation and what compliments have been achieved. In this thesis, the literature review is done by following the framework proposed in [30]. We review scientific papers (including journal and conference papers), scientific reports, and regulation documents on the topic of cost allocation in community energy systems, which cover technical, economic, social, and institutional design. Literature has been obtained by searching keywords and using forward and backward snowballing in electronic databases of Web of Science, ScienceDirect, Google Scholar, and Scopus. The strings used are 'cost allocation' or 'electricity pricing' with one of the words from ('integrated community energy systems', 'community energy systems', 'renewable energy community' and 'energy community') for the preliminary search in the article title, abstract and keywords. Subsequently, studies in English are selected but are the most relevant.

According to the literature review, the most widely used method to allocate costs in a local community context is game theory, and it is treated as a technical problem. Game theory is an effective tool to solve decision-making problems among two or more participants in situations where their decisions are interrelated [31]. In addition, players in the games are assumed that they can act rationally and strategically. There are two branches of game theory, namely, cooperative and non-cooperative games. A cooperative game analyzes the situation in which players follow the commitments made in the coalition and they act collectively. Two methods that are widely adopted in the cooperative game are the Shapley value and nucleolus. They vary with each other in their objectives. The Shapley value emphasizes fairness considering the individual marginal contribution, and the nucleolus focuses on minimizing the player's dissatisfaction with their payoffs [32]. In non-cooperative games, players are independent of each other and act individually. The important solution for non-cooperative games is the Nash equilibrium that players cannot improve their benefits by changing their actions if the other players keep the same decisions. In the context of cost allocation in energy communities, local community members (both consumers and prosumers) form a coalition in which they are considered players in the game. They act rationally with the objective of minimizing their electricity costs.

Several relevant works are illustrated in this section to present how they formulate the problems and what objectives they are trying to achieve besides cost allocation. The study in [33] proposes a day-ahead cooperative framework aiming to minimize both commodity and network costs in a low voltage electricity community. It emphasizes fair cost allocation by using game theory methods: the Shapley value and Nash equilibrium, in order to minimize the dissatisfaction of the players and allocate costs fairly among them in the community. Yang *et al.* proposed an *ex-post* cost allocation based on the nucleolus method to allocate the common costs of community energy storage. The community energy storage is cooperatively invested by multiple buildings within the community. The cooperative game is used to allocate costs (annual electricity costs) in an energy community consisting of both consumers and prosumers [32, 35]. The results show that both nucleolus and the Shapley value methods could provide stable cost allocations under minor deviations. In addition, the study also presents that cooperation among prosumers and consumers can lead to decreased electricity cost compared to individual operation [35]. Profits resulting from a coalition formation between multiple energy districts with DERs are allocated by using game theory methods in the study of [36]. The energy districts are a component of the smart grid, consisting of distributed generation, flexible and non-flexible loads, and energy storage devices. The profit allocation results highlight that the cooperation of DERs can achieve higher profits compared to the individual operation. Similarly, a cooperative game theory of the Shapley value method is adopted in [37] to allocate DERs and energy system network costs between individual stakeholders. In this case, it is four buildings that form a coalition. The annualized costs allocated to each building in the cooperative scenario are less than the non-cooperative one, proving that cooperation can save energy costs.

The Shapley value method is widely adopted because it offers a fair and equitable cost allocation result [37, 38]. A multi-energy coupling energy system with combined cooling, heating and power (CCHP) microgrid, and power to gas (P2G) facility is modeled in [39] to enhance energy efficiency as the excess renewable generation can be converted into natural gas. It is also an effective way to integrate multi-energy carriers in an energy system. In the energy system, the CCHP and P2G form cooperation that their integration will benefit both parties. Due to the involvement of different investors, the Shapley value cost allocation mechanism is adopted to fairly distribute the participants' operation costs for the integrated operation strategy. The cost allocation mechanism adopted in the study helps to save operation costs as cooperation compared to the situation of individual operation, and the costs are allocated to each facility (CCHP and P2G). Similarly, the Shapley value method is adopted to allocate benefits among community members in a renewable energy community, where producers and consumers form a coalition [40]. A mechanism for a fair redistribution of benefits from community-owned assets (wind turbines and battery) to individual prosumers is developed in [41] by using cooperative game theory. The redistribution mechanism is based on the marginal contribution of each player in the community to make it computationally tractable and practically applicable. The results show that community-owned assets provide higher benefits compared to individual-owned assets.

Besides game theory, there are also some other methods mentioned in the literature to solve the problem of cost allocation in community energy systems. Four cost allocation models are developed in [42] in order to investigate the costs allocated to each building in the community. The first model is to distribute the total costs to each building evenly. The second model is to allocate costs according to the load in each building. The third model allocates cost based on the level of zero energy target the building achieves. The level of zero energy target is achieved based on the reward-penalty mechanism. The main concept of the reward-penalty mechanism is that the building owner will receive a heavy penalty if the renewable energy source integration is low, and receive a reward if the renewable energy source integration is high. The value is determined by a coefficient, which is the ratio of its renewable generation to its load of the building. A value of 0 means no renewable generation for the targeted building, and a value of 1 represents the building achieving the zero energy target. The fourth model allocates cost concerning the two factors (load and the level of zero energy target) evenly. The four models allocate costs according to a coefficient that is determined by various factors. These methods are more direct compared to cooperative games.

1.3. Research findings and gaps

According to the literature view, it showed that the widely used method to allocate costs in the energy community is game theory. The game is based on the assumption that: players are rational and intelligent, and their decisions are made based on their desire to maximize their payoffs. However, it is not the case in real life. The solutions are often over-complicated and not easy to scale up. For example, the Shapley value cannot be determined in polynomial time to many cooperative games [43]. It is easy to compute the allocation results if a few players form the coalition. However, when it comes to the case with several dozens of individuals, the computation complexity increases, and it is time-consuming [41]. Game theory approaches also illustrate that a coalition provides higher benefits compared to an individual energy system. In addition, the game theory solutions do not show any information about their energy consumption in the final results, which are not cost reflective. Considering all the affecting factors, it, therefore, is not realistic to use game theory to allocate costs to the members in the community to get a practically applicable solution. The methods allocating costs according to a coefficient are more realistic compared to cooperative games. The costs are allocated according to some quantified criteria, such as the number of users, load demand, and the level of zero energy target.

The ICES considered in this thesis is a socio-economic energy system, which focuses on the integration of local DERs and local community members. The local community members have a common goal of contributing to energy transition by installing DERs either at the individual or community level. However, they need to pay for individual investment in DERs by themselves. They can also invest in community DERs to be investors by obtaining some benefits. It is also worth noting that the objective of local community members is not competing with each other to get benefits. Therefore it is not a competition-based community energy market. The cost allocation mechanism is not intended to incur competition among them, but to allocate costs or set electricity prices in a realistic manner, which can be easily implemented in practice and easy for local community members to understand and accept. They can actively participate in the decision-making process and take full control of the energy system. This is also different from the game theory perspective in that multiple actors form a coalition with the aim of saving energy costs. The objective of cost allocation in the ICES is to allocate the costs to the drivers that cause them to make it cost-causality. In addition, another consideration is that it is aimed at developing practical methods that can be applied to the energy community directly. There are currently no framework and methods about how to allocate costs in ICESs, how these methods are formulated, and what data are required. This is the first research gap.

The second research gap is that assessment criteria for the cost allocation methods are lacking in the current literature. Although it is not easy to evaluate their performance, it would add more value to the research to compare their performances and select the one with the most desirable performance.

The ICES considered in this thesis focuses on the integration of local community members. They play an important role in the energy system and are actively involved in the planning, development, and administration of the energy system as well as the allocation of its costs and benefit. It is essential to take their opinions and preferences into consideration. However, current research on cost allocation is formulated as a technical problem, which neglects the participation of local community members. This is the third research gap that social values are not taken into account in the process of cost allocation.

There are presently no criteria and approaches on how to allocate the costs in a local energy system, especially in an ICES mainly equipped with local DERs. Cost allocation for an energy system is often discussed in another field of study, namely tariff design in large power systems; it shows how the costs in those systems are allocated to the end-users. 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 [44], regulatory procedures [45, 46], regulatory principles [46–48] and cost allocation keys [49, 50]. In order to achieve a successful cost allocation in ICESs, it is recommended to review the tariff design issues in large power systems: (1) to investigate how to translate the concept of tariff design into cost allocation in ICESs, and (2) to review the cost allocation methods used in tariff design and explore their application to cost allocation in ICESs with appropriate modification.

1.4. Research objective and questions

Since ICESs are a rather new topic, many challenges exist in their implementation, which varies from technical, socio-economic, environmental to institutional issues [22, 51, 52]. 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 the investment does not automatically get the benefits that belong to it [53, 54]. 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. Cost allocation is the process of allocating costs to the local community members in the ICES. It could be in the form of energy (capacity) pricing or a direct amount of costs. The investments made in an ICES 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 [22].

In large power systems, the regulator makes decisions on tariff design according to the regulatory principles [45, 46]. However, no regulators are dealing with these issues in ICESs. The stakeholders in ICESs are local community members and investors. Local community members consume and share (prosumers) energy in ICESs. Investors make investments in local DERs. They may hold different points of view towards cost allocation in ICESs. For instance, investors want to recover the investments they made, local community members are in favor of fair cost allocation. The selected cost allocation method should protect the rights of consumers and the benefits of investors. The community itself needs to agree on the cost allocation method themselves. It, therefore, requires that the selected cost allocation method should be socially acceptable to local stakeholders. Studies in this area are often missing in the research of ICESs. Overall, the objective of this research is to help local community members to allocate costs in ICES in a socially acceptable manner. For this purpose, we develop a systematic framework for allocating costs in ICESs by taking into account the local community members' opinions and preferences. The main research question for this research is:

"How to design cost allocation in an ICES in a socially acceptable manner?"

The main research question is broken down into the following research sub-questions:

Sub-question 1: What can be learned from electricity tariff design with respect to cost allocation design in an ICES?

Sub-question 2: What is the framework for cost allocation design and which approaches can be adopted for cost allocation in an ICES?

Sub-question 3: How to assess the performance of the cost allocation methods?

Sub-question 4: How to select a socially acceptable cost allocation method?

1.5. Research method

This research mainly uses literature review and mathematical models and simulations to address the main and sub-questions presented in 1.4. These methods contribute to identifying the cost allocation design framework and conceptualizing social acceptance in the context of cost allocation ICESs. This research developed a systematic and quantitative model for allocating costs in ICESs in a socially acceptable manner. The literature review is used to identify what can be learned from electricity tariff design with respect to cost allocation design in ICESs, thus helping to develop a framework appropriate for cost allocation in ICESs. Modeling, simulation, and case studies are used to assess the performance of cost allocation methods, which are the essential inputs for analyzing social acceptance. These methods are the tools to facilitate the community to allocate costs with a fair procedure and fair results, which contribute to the social acceptance of local stakeholders.

1.6. Societal relevance

This thesis has practical relevance for different actors in the society vary from local community members, energy industries, electricity network operators to policymakers. These actors will not only be able to understand their changing roles, the provided economic values, but also their responsibilities within the transition of energy systems. This research can assist them in decision-makings and preparing for future changes.

Local community members are the fundamental components of the ICES. Their involvement is the key issue affecting the successful implementation of ICES. Therefore, this research is relevant for local community members who would like to invest in local DERs and operate the energy system jointly with the willingness to make contributions to climate change and energy transition. And it is also attractive to local community members who would like to participate in the decision-making process and take full control of their energy systems. The methodology developed in this thesis assists local community members in selecting a cost allocation method that is socially acceptable to them.

This research is relevant for energy industrial companies who wish to invest in DERs, to become an operator of an ICES and to benefit from the energy system. They can contribute to the implementation of cost allocation in ICESs by providing infrastructures and relevant services, such as smart meters, information and communication technology devices, and billing and billing collection services.

In addition, the outcomes of this research can also be beneficial for policymakers (or regulators), distribution network operators, and electricity market regulators. Policymakers can take more effective measurements to contribute to the implementation of local energy systems, such as by making proper regulations to regulate the activities of cost allocation in local community energy systems to protect the benefits of local community members. In addition, they can better formulate proper and tailored pricing mechanisms for local communities to further contribute to the formulation of local energy markets based on the cost allocation methods proposed in this thesis.

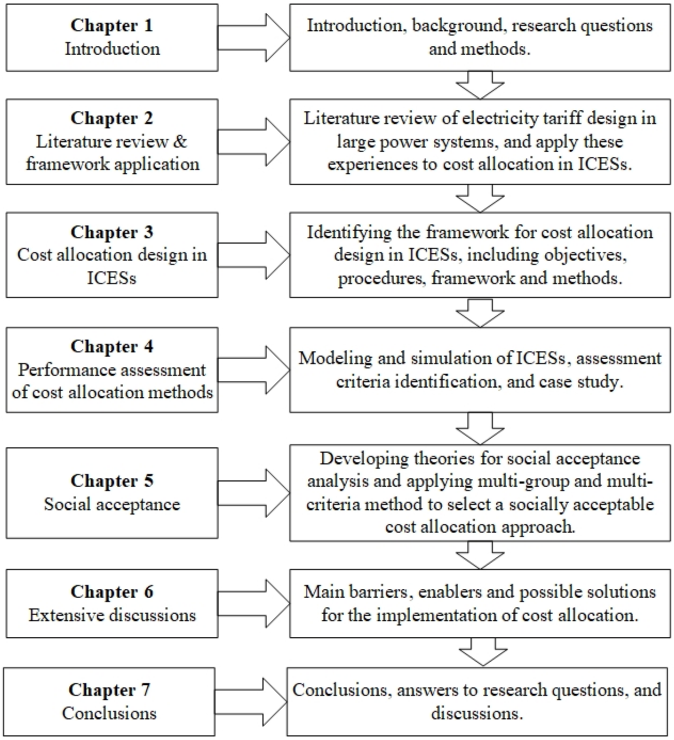

Figure 1.1: Structure of the thesis

1.7. Thesis outline

The structure of the thesis is summarized in Figure 1.1. Chapter 1 provides the research background and theoretical framework of this thesis. Chapter 2 gives a comprehensive review on the main issues involved in cost allocation in tariff design, which are the essential theoretical foundation of this research. We summarize tariff design objectives, cost allocation procedures and the underlying regulatory principles for major tariff approaches and discuss how these concepts may be applied to cost allocation in ICESs. Chapter 3 presents the cost allocation framework and approaches for ICESs derived from tariff design. Chapter 4 assesses the performance of cost allocation methods based on a case study in terms of the two criteria: cost reflectiveness and cost predictability. Chapter 5 analyzes the social acceptance of cost allocation in ICESs by using the multi-group multi-criteria decision-making method. Chapter 6 presents an extensive discussion on the main barriers and enablers in the implementation of cost allocation in ICESs. Chapter 7 answers the research questions and discusses the various findings from the research and draws the conclusions.

2

Cost allocation in tariff design: a review

Nature and nature's laws lay hid in the night;
God said 'Let Newton be!' and all was light.

Alexander Pope

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. Many issues are involved in tariff design in order to allocate costs in a proper manner. However, a systematic framework for allocating costs in ICESs is still lacking in current research. Clear procedures and objectives are required to be defined in order to ensure a successful implementation of cost allocation.

In this chapter, we address the research sub-question: "What can be learned from electricity tariff design with respect to cost allocation design in an ICES?". The aim of this chapter is to review the objectives, regulatory procedures, tariff structure design, regulatory principles, and cost allocation methods for tariff design in large power systems. Additionally, we aim to gain an understanding of how these can be applied to cost allocation in an ICES. For this purpose, it is necessary to have a comparison between large power systems and ICESs to know their differences. And then, we summarize tariff design objectives, cost allocation procedures, and the underlying regulatory principles for tariff design and discuss how these concepts may be applied to cost allocation in an ICES. The most widely used cost allocation methods are explained mathematically, as well as their advantages and disadvantages. And the application of each method in an ICES is discussed extensively. Firstly, a comparison between large power systems and ICESs is presented in Section 2.1. And then, a detailed overview of electricity tariff design includes definition, objectives, regulatory procedures, tariff structure design, and regulatory principles is provided in Section 2.2, followed with a discussion of how these concepts can be applied to the case of cost allocation in an ICES in Section 2.3. Section 2.4 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. Finally, Section 2.5 draws the conclusions.

This chapter is a slightly modified version of the paper "Cost allocation in integrated community energy system - A review" published in the journal of Renewable and Sustainable Energy Reviews [55].

2.1. Comparison between large power systems and ICESs

2.1.1. 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) [56, 57]. In a competitive electricity market, generation and supply become competitive activities, the energy price is determined by the electricity market (also with tax on energy), and transmission and distribution activities are considered natural monopolies under regulation [57, 58]. 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 [59].

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.

2.1.2. Integrated community energy systems

ICESs are local community energy systems consisting of two fundamental components: local DERs and a local community [18]. A general framework of an ICES is shown in Figure 2.1. The power is generated by local DERs (such as solar panels and small-scale wind turbines) and directly delivered to local consumers. 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

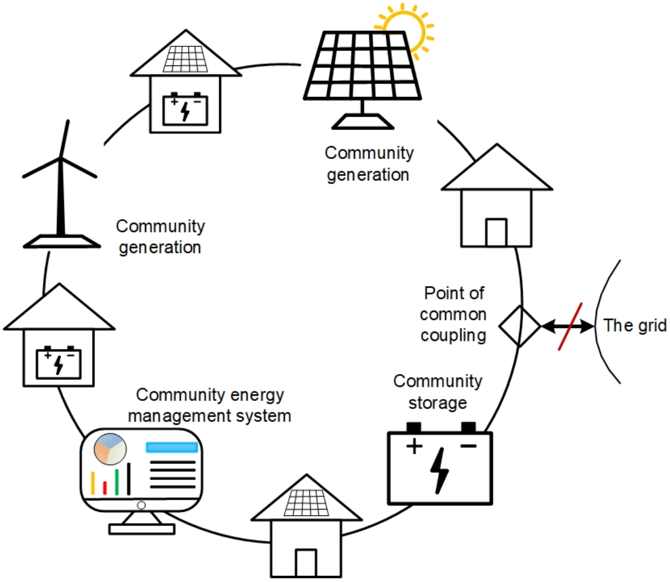

Figure 2.1: A general structure of an ICES [1]

quality and voltage control, frequency 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 [22]. 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.

2.1.3. Comparison

This subsection summarizes the similarities and differences between large power systems and ICESs. Table 2.1 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 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

Table 2.1: 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

Table 2.2: 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 costs (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)

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 network 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 2.2. 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 [18, 22]. 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.

2.2. 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, followed with a discussion of how these concepts can be applied into the context of cost allocation in ICESs.

2.2.1. Electricity tariff

As shown in Figure 2.2, before the liberalization of electricity market, all these charges paid by the end-users are determined and set by the regulatory authorities [60]. 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 [61]. 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. In this thesis, we mainly focus on the transmission and distribution network tariff design, which are determined by the regulators.

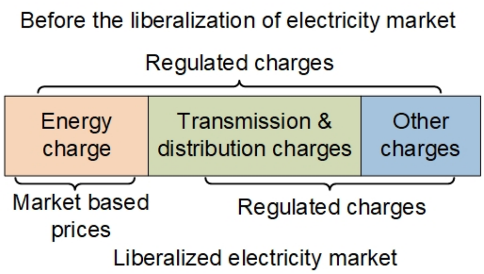

Figure 2.2: Electricity tariffs before and after the liberalization of electricity market

Tariffs are basically a group of charges reflecting the costs of each activity. These charges consist of transmission network charges, distribution network charges and regulated taxes. A tariff is the interconnection between electricity companies and the

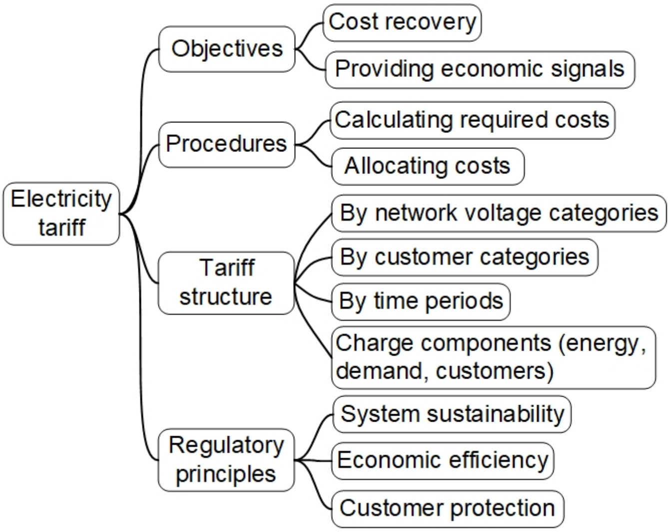

Figure 2.3: Key issues in electricity tariff design

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 Figure 2.3. 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.

2.2.2. 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 [45, 61]. In a liberalized electricity market, the cost recovered is for network-related businesses. In general, this is the basic objective to achieve 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-users [45, 61]. 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 [62]. 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.

2.2.3. 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 [45, 46]. 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 [63, 64]. Two phases involved in this step [45]: (1) defining the tariff structure and (2) calculating the final charges.

The two steps in tariff design are consistent with the objectives defined in 2.2.2. 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.

2.2.4. 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 [46]. In addition, the structure of the tariff should be concise and simplified, while revealing the underlying complexity of rate calculation and energy billing costs [64]. Tariff structures should include the drivers that cause the system costs and reflect the underlying cost structure [45, 46, 65]. Typically, the components in electricity tariffs include [45, 66]: (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 [50].

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 [67–69], real-time price or critical peak price [60, 70]. 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 to ensure the load demand is not so high that the power system starts to collapse.

2.2.5. 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 and to achieve the two objectives defined in 2.2.2. 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 [47, 71], which are presented in Figure 2.4.

- **Economic 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 [45]. It is easy to measure to which extent the tariffs satisfy sustainability according to the costs recovered through them.

- **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 [50, 64]. 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

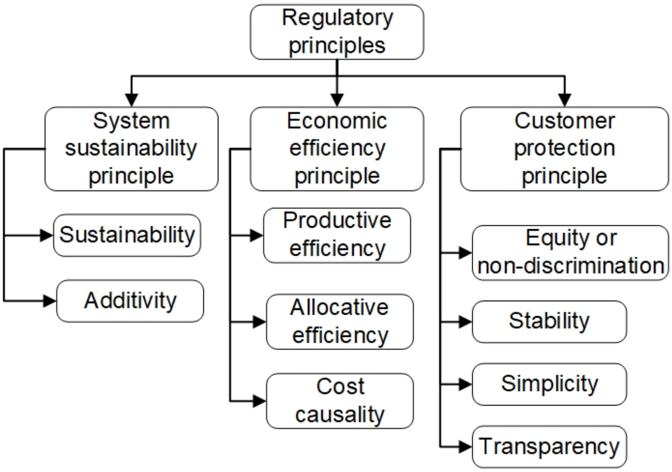

Figure 2.4: Summary of regulatory principles

standards [49]. 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 [47]. 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 [72, 73]. 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 [46, 74]. 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 [75].

- **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 [62].
- **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 [66].

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 [66]. 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.

2.3. Applicability of tariff design to cost allocation in 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 [71]. 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.

2.4. Review of cost allocation methods

There are many successful examples of cost allocation methods applied in tariff design in large power systems. 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 [47]. 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 [76]. 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 [47], 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. In this chapter, the cost allocation approaches applied in distribution network tariff design are reviewed for application as cost allocation methods in ICESs. 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.

2.4.1. Flat energy pricing method

Approach

This method allocates costs according to the total amount of energy consumption, irrespective of the time of energy consumption [67, 69, 77]. 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 [78]. It is the most straightforward method for calculating energy price: dividing energy-related costs by the volume of total energy consumption [79]. Consumers pay electricity bills at a flat rate per kWh. The flat energy price P_f (€/kWh) is calculated as:

$$P_f = \frac{TC}{\sum_{i=1}^{N} \sum_{t=1}^{T} E_i(t)} \tag{2.1}$$

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

$$C_i = P \times \sum_{t=1}^{T} E_i(t) \tag{2.2}$$

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 [63, 80].

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.

2.4.2. Base and peak method

Approach

The base and peak method has a two-part allocator factor [81]. 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 [82]. 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 [82]. The study in [67] 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 [83] 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 [81]. The costs allocated to base TC_{base} (€) and peak hours TC_{peak} (€) are calculated as:

$$TC_{base} = TC_1 \times \frac{T_{base}}{T} \tag{2.3}$$

$$TC_{peak} = TC_1 \times (1 - \frac{T_{base}}{T}) + TC_2 \tag{2.4}$$

where TC_1 (€) are the costs for satisfying base demand, and TC_2 (€) are the costs for satisfying 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:

$$P_{base} = \frac{TC_{base}}{E_{base}} \tag{2.5}$$

$$P_{peak} = \frac{TC_{peak}}{E_{peak}} \tag{2.6}$$

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 $C_i(t)$ (€) for customer i is:

$$C_i(t) = \begin{cases} P_{base} \times E_i(t) & t \in T_{base} & \text{(2.7a)} \\ P_{peak} \times E_i(t) & t \in T_{peak} & \text{(2.7b)} \end{cases}$$

where $E_i(t)$ (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:

$$C_i = \sum_{t=1}^{T} C_i(t) \tag{2.8}$$

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.

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. It does not reflect the impact of peak demand of customers on the system. The advantages of this method outweigh its disadvantages.

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.

2.4.3. Marginal cost pricing method

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 [84–86]. Normally, this provides the hourly energy price, which could be regarded as real-time pricing [63, 80, 87]. 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 [88, 89].

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 [90, 91]. It includes both long-term operation, investment and reinforcement costs [92]. 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 as many possible short-term marginal costs as there are possible future scenarios [46]. 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) [84, 93, 94].

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 [94]. The marginal cost MC (€/kW(h)) is calculated as:

$$MC = \frac{dTC(Q)}{dQ} \tag{2.9}$$

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

Incremental cost IC (€/kW) is calculated as:

$$IC = TC(Q + \Delta Q) - TC(Q) \tag{2.10}$$

Advantages and disadvantages

Both marginal and incremental cost can be applied in the cost allocation for generation [81], transmission [95–97] and distribution network activities [46, 61]. 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 [89, 98, 99]. 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 [96]. Neither short-term marginal cost nor long-term marginal cost can ensure cost recovery [46, 100]. 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.

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 [61, 88]. The coefficients used are multiplier and additive [100–102]. The first adjustment is to multiply a ratio of the allowed costs to the marginal based-revenues [103]. 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 [61]. 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) [80]. 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 [104, 105], 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.

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 [106–111]. 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, diving 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.

2.4.4. Average and excess method

Approach

The average and excess method allocates costs using factors that combine the customers' average and non-coincident peak demands [81, 112]. It has a two-part allocation factor [113, 114], 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:

$$f_{1,\ i} = \frac{E_{ave,\ i}}{\sum_{i=1}^{N} E_{ave,\ i}} \times lf \tag{2.11}$$

$$f_{2,\ i} = \frac{E_{exc,\ i}}{\sum_{i=1}^{N} E_{exc,\ i}} \times (1 - lf) \tag{2.12}$$

$$E_{exc,\ i} = E_{peak,\ i} - E_{ave,\ i} \tag{2.13}$$

$$lf = \frac{\sum_{i=1}^{N} E_{ave,\ i}}{E_{peak}} \tag{2.14}$$

where $f_{1,\ i}$ and $f_{2,\ i}$ are the two-part allocation factors of customer i, $E_{ave,\ i}$, $E_{peak,\ i}$ and $E_{exc,\ i}$ (kW) are the average, peak and excess demand of customer i, E_{peak} (kW) is the system peak demand. lf is load factor of the whole energy system.

The final cost allocated to consumer i is:

$$C_i = (f_{1,\ i} + f_{2,\ i}) \times TC \tag{2.15}$$

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.

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.

2.4.5. Ramsey pricing method

Approach

The Ramsey pricing method allocates costs in inverse proportion to price elasticity [115, 116]. 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) [80, 117]. It is normally used in cases in which the marginal cost is below the average cost, which would make the utility companies make losses [118]. The studies in [99] and [116] 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 [117], 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 [99, 116, 119]. The mathematical expression for calculating Ramsey pricing according to research [63, 99] is :

$$\frac{P_i - MC_i}{P_i} = \frac{\lambda}{1+\lambda}\frac{1}{\eta_i} \tag{2.16}$$

where P_i (€/kWh) is the electricity price for customer group i, MC_i (€/kWh) is the marginal cost for 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.

Advantages and disadvantages

The advantage of Ramsey pricing is obvious, in that it can maximize social welfare. However, there are two main drawbacks to Ramsey pricing which make it hard to apply in practice [64]. 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.

Applicability to ICESs

Energy generation in ICESs is almost all from RESs. The marginal costs for RESs are zero [106–108], 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.

2.4.6. Postage stamp method

Approach

The postage stamp method is widely used in European countries for transmission network cost allocation [120–122]. It allocates the allowed revenue according to the magnitude of the transacted power, which is measured at the time of the system peak demand [38, 123–125]. The transmission network price P_{TN} (€/kW) is calculated as:

$$P_{TN} = \frac{TC}{\sum_{i=1}^{K} E_{tran,\ i}} \tag{2.17}$$

where $E_{tran,\ i}$ (kW) is the peak demand of transaction i. K is the number of transactions. Therefore the transmission network cost for transaction i is:

$$C_i = P_{TN} \times E_{tran,\ i} \tag{2.18}$$

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[93, 126, 127]. According to the study in [123], the postage stamp method is favored by investors, because the tariff is stable and predictable.

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.

2.4.7. Contract path method

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 [95, 128]. It is also mostly used in cost allocation in the transmission network. The transmission network price P_{TN} (€/kW) is calculated as:

$$P_{TN} = \frac{TC}{\sum_{i=1}^{R} E_{path,\ i}} \tag{2.19}$$

where $E_{path,\ i}$ (kW) is the magnitude of power signed in the contract for path i. R is the number of contract paths. Therefore, the network cost for customer i is:

$$C_i = P_{TN} \times E_{path,\ i} \tag{2.20}$$

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 [84, 93]. Neither the postage stamp nor contract path methods take the actual operating environment of the system into account.

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 [129]. 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.

2.4.8. Distance-based-MV-mile method

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 [122, 130]. 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 [38]. The transmission network price is proportional to the MW-mile value and is calculated as:

$$P_{TN} = \frac{TC}{\sum_{i=1}^{K} PX_i} \tag{2.21}$$

$$PX_i = L_i \times E_{tr,\ i} \tag{2.22}$$

where PX_i (MW $\cdot$ mile) is MW-mile value, L_i (mile) is the geographical distance between seller and buyer of transaction i, $E_{tr,\ i}$ (kW) is the magnitude of the transacted power.

The transmission network cost for transaction i is:

$$C_i = P_{TN} \times PX_i \tag{2.23}$$

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 [122]. However, it is hard to show the relationship between the transacted power and the power flow transported [93].

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.

2.4.9. Power-flow-based-MV-mile method

Approach

The power-flow-based-MW-mile method allocates the transmission network cost based on the magnitude of power flow [131, 132]. It is a power flow based cost allocation method, the cost is recovered by power flow charges [38, 93, 133]. The transmission network price is calculated as:

$$P_{TN} = \frac{TC}{\sum_{i=1}^{K} \sum_{j=1}^{Z} c_j L_{i,j} E_{i,j}} \tag{2.24}$$

where Z 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, $E_{i,j}$ (kW) is the power flow in circuit j caused by transaction i. The transmission network cost for transaction i is:

$$C_i = P_{TN} \times \sum_{j=1}^{K} c_j L_{i,j} P_{i,j} \tag{2.25}$$

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 [126]. 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.

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 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.

2.4.10. Coincident peak method

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) [81, 134]. It is usually used in transmission and distribution network cost allocation in the United States and the United Kingdom [135, 136]. 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 reduction of the 4-CP is much larger than the 1-CP [137], as it encourages demand response during peak hours. The coincident peak demand charge P_{CP} (€/kW) is calculated as:

$$P_{CP} = \frac{TC}{\sum_{i=1}^{N} E_{CP,\ i}} \tag{2.26}$$

where $E_{CP,\ i}$ (kW) is peak demand of customer i occurring at the system peak hours. The cost allocated to customer i is:

$$C_i = P_{CP} \times E_{CP,\ i} \tag{2.27}$$

Advantages and disadvantages

A coincident peak method is cost-reflective, the costs reflect the individual's contribution to the system peak demand [91]. However, these methods ignore load information, such as load factor and energy consumption [114]. 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.

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.

2.4.11. Non-coincident peak method

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 [81, 113]. It is based on the theory that the system could satisfy all the customers' maximum demand. The non-coincident peak demand charge P_{NCP} (€/kW) is calculated as:

$$P_{NCP} = \frac{TC}{\sum_{i=1}^{N} E_{peak,\ i}} \tag{2.28}$$

The cost allocated to customer i is:

$$C_i = P_{NCP} \times E_{peak,\ i} \tag{2.29}$$

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.

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.

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.

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

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 [61, 138]. 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 [139]. 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 [46] 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 [46, 61]. The cost-causality based method is studied in [134]; 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 [81, 112, 113], 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 [45, 112]. Cost drivers are the key factors that drive the total costs of the power system [61, 138]. 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 [140–142], 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 [82]. 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.

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.

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, operation and maintenance 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.

2.4.13. Summary and discussions

Table 2.3 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.

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.

Table 2.3: Summary of cost allocation methods

Number	Method	Pricing components	Time dependent (Yes/No)	Location based (Yes/No)	Applicable in ICESs (Yes/No)	Ease of application	Reference
1	Flat energy pricing method	Energy	No	No	Yes	+ + +	[60, 64, 67, 69, 77]
2	Base and peak method	Energy	Yes	No	Yes	+ +	[81]
3	Marginal cost pricing method	Energy Capacity	Yes	No	No	—	[46, 61, 84–86]
4	Average and excess method	Capacity	No	No	Yes	+ +	[81, 112–114]
5	Ramsey pricing method	Energy	Yes	Yes	No	—	[57, 63, 80, 115–117]
6	Postage stamp method	Capacity	No	Yes	Yes	+ + +	[84, 85, 120–122]
7	Contract path method	Capacity	No	Yes	No	—	[84, 85, 123, 125]
8	Distance-based-MW-mile method	Capacity	No	Yes	No	—	[84, 85, 95, 122, 130]
9	Power-flow-based-MW-mile method	Capacity	No	Yes	No	—	[84, 121, 131, 132]
10	Coincident peak method	Capacity	No	No	Yes	+ + +	[81, 112, 134]
11	Non-coincident peak method	Capacity	No	No	Yes	+ + +	[47, 81, 112, 113]
12	Cost allocation based on cost-causality principle method	Energy Capacity Customer service	No	No	Yes	+	[45, 61, 138]

+ 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.

2.5. Conclusions

This chapter presents a brief overview of the key issues included in tariff design in large power systems and a comprehensive review of cost allocation methods. Firstly, 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. Secondly, learning from experience with electricity tariff design, discussions on the application issues of these cost allocation approaches are included. The review paves the way for the application of fair cost allocation in ICESs by providing a systemic framework and achievable cost allocation methods.

3

Cost allocation design in integrated community energy systems

Time plays a role in almost every decision.
And some decisions define your attitude about time.

John Cale

In an ICES, there is no regulator making regulations and no rules on how to allocate costs. Therefore, a set of regulations and rules are required to be made in ICESs in order to achieve a successful implementation of cost allocation. In this chapter, we address the research sub-question: "What is the framework for cost allocation design and which approaches can be adopted for cost allocation in an ICES?". Based on the review in Chapter 2, the objectives, procedures, and required components for allocating costs in ICESs are defined and elaborated in detail. In addition, tailored cost allocation methods are derived and formulated based on the methods applied for tariff design in large power systems.

The objectives, procedures, and framework for cost allocation in ICESs are provided in Section 3.1, Section 3.2, and Section 3.3, respectively. The approaches that can be adopted for cost allocation in ICESs are presented in Section 3.4. Finally, Section 3.5 concludes the work in this chapter.

This chapter is a slightly modified version of the paper "Cost allocation in integrated community energy systems - Performance assessment" submitted to the journal of Applied Energy, which is in press at this moment[143].

3.1. Objectives

Local community members are the fundamental components in an ICES, their involvement is essential in the implementation of ICESs. Their preferences and opinions should be carefully taken into account and the way the costs are allocated and the method selected should be socially acceptable to the them. Therefore, besides the two objectives mentioned in tariff design: (1) to recover the total costs, and (2) to send economic signals to the end-users, another objective that has to be taken into account is (3) to allocate costs in a socially acceptable manner. Thus, the three objectives together ensure the success of cost allocation in an ICES.

3.2. Procedures

In ICESs, the procedure is much more complex compared to the ones in tariff design since the local community members decide on the method to allocate costs. The first step is the same as in tariff design, which is to define the total costs that need to be recovered from local community members. The costs are the various expenses incurred from generating and supplying electricity to local community members. The costs mainly include capital investment costs, O&M costs and customer management costs. ICESs require the engagement of local community members, their points of view should be taken into account when allocating costs. Many methods can be used to allocate costs in ICESs, and they differ from each other in characteristics. Local community members have different preferences towards different characteristics. Therefore, the second step is to select a cost allocation method by the decision-making from the local community members. It therefore requires a decision-making framework considering the opinions and requirements from local

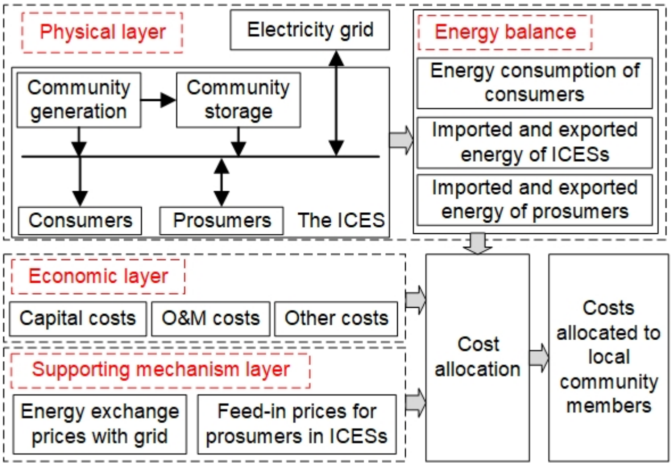

Figure 3.1: Framework of cost allocation in ICESs

community members to help them arrive at consensus. The final step is to allocate costs to local community members based on the selected method in the second step and formulate the energy bills for each local community member.

3.3. Cost allocation framework

A clear and concise framework is required to ensure successful cost allocation in ICESs, since they are different from general power systems. Figure 3.1 shows the cost allocation framework in ICESs. This comprises several layers: the physical, the economic, and the supporting mechanism. Each of these layers focuses on different aspects of the design and provides essential inputs to the cost allocation model. They are therefore described in turn in the following sections.

3.3.1. Physical layer

The physical layer presents how the energy system works: specifically, how power and information flow among the different actors in the system. A basic framework of the physical system of the ICES under consideration is shown in Figure 3.2. Community generation (solar panels and wind turbines) produces energy and supplies it to local community members (consumers and prosumers). Community storage is used to dispatch energy within the community, being charged from surplus generation and discharged when generation is not sufficient. Local community members can invest in DERs (storage, solar panels or both) to become prosumers. The local community forms a cooperative to exchange energy with the grid. In addition, even though the ICES considered in this thesis is grid-connected, the objective of the community is to be self-sufficient. Therefore, energy exchange with the grid is very limited. The whole energy system is controlled by a community energy management

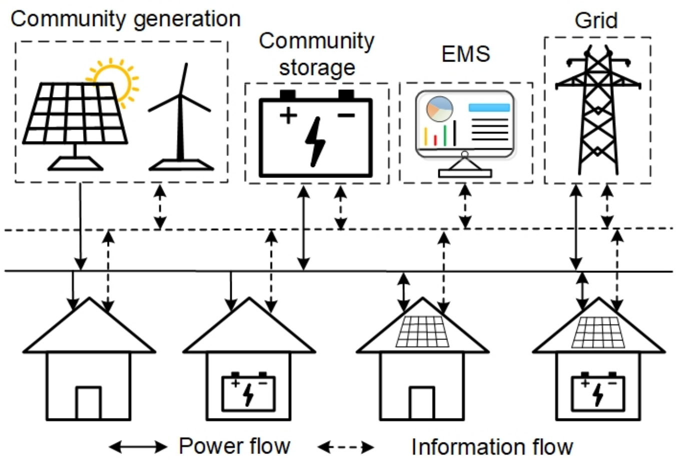

Figure 3.2: A physical ICES system

system. The outputs of this physical layer are energy consumption and exchange data, collected at the individual and community levels. This data is necessary information for allocating costs in an ICES. Furthermore, these outputs are considered as the inputs of cost allocation.

3.3.2. Economic layer

The economic layer includes the various costs that are used to purchase infrastructures and cover management fees. These costs plus the energy exchange costs with the grid are the total costs required to be recovered from cost allocation. Principally, they comprise capital, O&M, and other costs. Capital costs are the investment in purchasing and installing DERs. O&M costs are mainly expenses for infrastructure maintenance. These two kinds of costs vary with the overall capacity of the DERs. Other costs are mainly customer management expenses, such as metering, grid connection, and energy billing.

3.3.3. Supporting mechanism layer

The supporting mechanism layer comprises the arrangements needed to ensure successful energy exchange within an ICES and with the grid. Such a mechanism can be regarded as the rules that local community members should follow once they agree to join an ICES. Specifically, these mechanisms are defined as follows.

1. Prosumers are required to pay for their own investments in individual DERs. This cost is incurred through personal action, and so is not considered part of the cost of the system as a whole. The objective of an ICES is to satisfy local demand from local generation by building a local energy system. The costs requiring allocation are common costs of providing electricity to local community members,

which includes costs of community DERs and the community energy management system, energy purchases and other related costs.

2. Consumers and prosumers are required to consume energy within the community. Moreover, prosumers are required to sell surplus energy to the community in order to achieve efficient utilization of local generation. The ICES in this study acts as an aggregator, purchasing energy from and selling it to the grid on behalf of the whole community as a collective.

3. The feed-in price for prosumers is determined by the mechanism adopted; for instance, periodic compensation, net energy exchange [144], full peer-to-peer (P2P) energy trading, and community-based P2P energy trading [145, 146]. Each trading mechanism has its advantages and disadvantages; which is selected depends on the local situation and the practical complexity of implementation. This study takes community-based P2P energy trading as the energy exchange mechanism used. In order to ensure benefits for local community members and provide incentives for them to stay in the ICES in the long term, the supporting mechanism of energy exchange must satisfy the following criteria: (1) from the prosumer perspective, the energy selling price to the community is at least equal to the feed-in price to the grid; and (2) from the consumer perspective, the energy selling price is no higher than the price of purchasing energy directly from the grid.

3.4. Cost allocation methods

This section presents methods that can be used to allocate costs in ICESs. Some of these methods have already been adopted in tariff design, but the implementation mechanism may not be the same due to the differences between large power systems and ICESs. In addition, some methods, such as flat energy pricing, coincident peak pricing and others, have been introduced in the previous chapter, however, the required data and their formulations are may not the same as in large power systems. Therefore, methods adopted in large power systems and can be applied in ICESs are explained in detail to show how their concepts are translated from tariff design and how they are derived from underlying principles. The methods are also formulated mathematically, to show how they are implemented and what data are required. Furthermore, new methods are also developed in this section.

3.4.1. M1: Cost allocation based on number of users

In this method, costs are allocated based on the number of users in the community. It is the method adopted in [42], where it is considered the simplest method to allocate the total costs evenly to each building. Every local member pays exactly the same. It is formulated as:

$$C = \frac{TC}{N} \tag{3.1}$$

where C (€/household) is the cost allocated to each household in the community, TC (€) is total costs, and N is the number of households. The only two required data items are the total cost of the ICES and the number of community members. This approach can thus be implemented without requiring any kind of measuring equipment. It is straightforward to understand and simple to compute. The biggest disadvantage is that it does not take actual consumption into account so that, especially in cases where some households consume a lot of energy and other very little, it is unfair on the latter because they pay the same as everyone else. Nevertheless, it still makes sense if all the households involved have similar energy consumption behavior. Technically speaking, it is easy to implement this method in any energy system.

3.4.2. M2: Flat energy pricing

In this approach, the cost is allocated based on total energy consumption within a predefined time period, such as one month or one year. The energy price is fixed during that specific period [60, 77]. Consumers pay for their electricity at a flat rate per kWh [78]. The energy price P_f (€/kWh) is calculated as:

$$P_f = \frac{TC}{\sum_{i=1}^{N} \sum_{t=1}^{T} E_i(t)} \tag{3.2}$$

where $E_i(t)$ (kWh) is the hourly energy consumption of household i. The required data items are total costs and hourly energy consumption, which can be measured by smart meters. The energy price is time-independent; local community members are all charged the same rate during the predefined time period.

3.4.3. M3: Time-of-use energy pricing

Time-of-use (ToU) energy pricing is aimed at differentiating energy prices between peak and off-peak hours [50, 147]. The price in each time period is fixed, and is higher in peak hours and lower in off-peak hours [67]. According to [81], the rules for cost allocation are that costs of satisfying base demand are allocated to the two periods and the costs of satisfying peak demand are allocated to peak hours only. In large power systems, generators are dispatched according to load demand at different times. It is therefore easy to calculate the costs incurred in different time periods from the actual operational situation. In an ICES, however, it is not easy to differentiate costs during the two periods, because energy generation by RESs is non-dispatchable. In this thesis, it is proposed that the costs be allocated to the two periods by taking into account load factor and peak and off-peak time blocks.

The two resulting prices (€/kWh) are formulated as:

$$P_{base} = \frac{C_{base}}{\sum_{t=1}^{T_{base}} E_{base}(t)} \tag{3.3}$$

$$P_{peak} = \frac{C_{peak}}{\sum_{t=1}^{T_{peak}} E_{peak}(t)} \tag{3.4}$$

$$C_{base} = TC \times lf \times \frac{T_{base}}{T} \tag{3.5}$$

$$C_{peak} = TC \times \ lf \times (1 - \frac{T_{base}}{T}) + TC \times (1 - lf) \tag{3.6}$$

$$TC = C_{base} + C_{peak} \tag{3.7}$$

where P_{base} and P_{peak} (€/kWh) are the energy prices in off-peak and peak hours respectively, C_{base} and C_{peak} (€) are the costs in off-peak and peak hours during time period T, T_{base} and T_{peak} (hours) are the total off-peak and peak hours during time period T, and $E_{base}(t)$ and $E_{peak}(t)$ (kWh) are energy consumption in the ICES in off-peak and peak hours. lf is the load factor, defined as the ratio between average energy consumption and peak demand [148]:

$$lf = \frac{\frac{1}{T}\sum_{t=1}^{T} E(t)}{E_{peak}} \tag{3.8}$$

where $E(t)$ is the hourly energy consumption of the system during time period T. The hourly energy cost $C_i(t)$ (€) for household i is:

$$C_i(t) = \begin{cases} P_{base} \times E_i(t) & t \in T_{base} \quad (3.9a) \\ P_{peak} \times E_i(t) & t \in T_{peak} \quad (3.9b) \end{cases}$$

The data required for this method, so as to calculate total energy consumption in peak and off-peak hours, includes total costs, off-peak hours, peak hours, hourly energy consumption. Smart meters are required to gather the hourly energy consumption data. This pricing mechanism incentivizes users to reduce energy consumption in peak hours or to shift it to off-peak hours by charging a higher price during peak hours. From a technical perspective, the energy prices can be provided *ex-ante* by using historical data or *ex-post* (for instance, at the end of the month) by using real data. This depends on the strategy adopted by the local community, although the pricing mechanism used should always be clear to its members.

3.4.4. M4: Capacity subscription

The idea behind this method is that each consumer subscribes to a certain amount of DER capacity according to their consumption levels. The total generation from the DERs is determined by the capacity installed. This installed capacity is calculated by the simple rule that annual generation equals annual energy consumption [129]. The capacity price P_{CS} (€/kW) is formulated as:

$$P_{CS} = \frac{TC}{\sum_{i=1}^{N} CS_i} \tag{3.10}$$

where CS_i (kW) is the capacity of DERs subscribed by household i, P_{CS} is the subscribed capacity price (€/kW). The two required data items are total costs and the DER capacity subscribed to by each household, which can be estimated at the beginning of the project by means of historical consumption data. This method simplifies the process of allocating costs and is easy to implement in practice.

3.4.5. M5: Coincident peak pricing

In this approach, the costs are allocated based on the peak demand contribution of each household to the total system peak demand within the predefined time period, such as one month, one season or one year [81, 137]. The capacity price P_{CP} (€/kW) is formulated as:

$$P_{CP} = \frac{TC}{\sum_{i=1}^{N} E_{CP,\ i}} \tag{3.11}$$

where $E_{CP,\ i}$ (kW) is the peak demand by household i, which is coincident with the system peak demand in time period T. The required data items are total costs and the peak demand of each household that happened at the system peak time. It is possible to obtain individual peak demand data using smart meters. The pricing signal indicates how consumers' peak demand affects their energy bills and incentivizes them to reduce peak demand.

3.4.6. M6: Non-coincident peak pricing

The principle underlying non-coincident peak pricing is to allocate costs based on individual peak demand [112, 113]. The difference between this method and the coincident peak pricing is that individual peak demand may not coincide with system peak demand. The capacity charge P_{NCP} (€/kW) is formulated as:

$$P_{NCP} = \frac{TC}{\sum_{i=1}^{N} E_{NCP,\ i}} \tag{3.12}$$

where $E_{NCP,\ i}$ (kW) is the individual peak demand by household i. The required data items are total costs and individual household peak demand. The pricing signal indicates how consumers' peak demand influences their energy bills. This is an effective way to incentivize consumers to reduce their individual peak demand, no matter when system peak demand occurs.

3.4.7. M7: Segmented energy pricing

The idea of segmented energy pricing is that electricity is sold at different prices for different consumption levels [149]. Consumers are charged at the base price when their consumption level is below a defined threshold, and at another price for any consumption exceeding that. The excess component is the difference between individual peak and average energy consumption (or demand). The threshold is determined using the hourly average energy consumption by households. The total costs in time period T are classified based on load factor. Segmented energy pricing is formulated as:

$$P_{ave} = \frac{TC \times lf}{\sum_{i=1}^{N} \sum_{t=1}^{T_{ave}} E_{ave}(t)} \tag{3.13}$$

$$P_{exc} = \frac{TC \times (1 - lf)}{\sum_{i=1}^{N} \sum_{t=1}^{T_{exc}} E_{exc}(t)} \tag{3.14}$$

$$T = T_{ave} + T_{exc} \tag{3.15}$$

where P_{ave} (€/kWh) is the energy price when consumption is below the base threshold, P_{exc} (€/kWh) is the energy price for the component of energy consumption exceeding that threshold, T_{ave} and T_{exc} (hours) are the hours of consumption below and exceeding the threshold, respectively, and $E_{ave}(t)$ and $E_{exc}(t)$ (kWh) are consumption below and exceeding the threshold.

The hourly energy bill structure for household i is:

$$C_i(t) = \begin{cases} P_{ave} \times E_i(t) & E_i(t) \leq E_{th} \quad (3.16a) \\ P_{ave} \times E_{th} + P_{exc} \times (E_i(t) - E_{th}) & E_i(t) > E_{th} \quad (3.16b) \end{cases}$$

Where $E_i(t)$ (kWh) is the hourly energy consumption by household i, and E_{th} (kWh) is the threshold value. The required data items for this method are total costs, hourly energy consumption by each household, which are easy to obtain using smart meters. This method focuses on consumption level, regardless of the time of consumption. Customers are incentivized to pay attention to their energy consumption all the time and try to keep this below the threshold in order to minimize its cost. It thus provides a good incentive to adjust consumption behavior. Similar to the ToU energy pricing method, the price signal can be provided either *ex-ante* or *ex-post*, according to the strategy adopted by the local community.

3.4.8. M8: Average and excess pricing

The underlying principle of the average and excess method is to allocate costs directly to users by means of two factors [81, 112]. The first of these presents average consumption by each customer in relation to the average for the entire system. The second shows excess energy consumption by each customer in relation to excess energy consumption in the system as a whole (which equals peak demand minus average energy consumption). The two factors and the energy bills are formulated as:

$$f_{1,\ i} = \frac{E_{ave,\ i}}{\sum_{i=1}^{N} E_{ave,\ i}} \times lf \tag{3.17}$$

$$f_{2,\ i} = \frac{E_{exc,\ i}}{\sum_{i=1}^{N} E_{exc,\ i}} \times (1 - lf) \tag{3.18}$$

$$E_{exc,\ i} = E_{peak,\ i} - E_{ave,\ i} \tag{3.19}$$

$$C_i = (f_{1,\ i} + f_{2,\ i}) \times TC \tag{3.20}$$

where $f_{1,\ i}$ and $f_{2,\ i}$ are the two-part allocation factors for customer i, $E_{ave,\ i}$, $E_{exc,\ i}$ and $E_{peak,\ i}$ (kW) are the average demand, excess demand, and peak demand by user i, respectively. C_i is the energy cost of household i. The required data items are total costs and the hourly energy consumption by each household. The two factors indicate consumers how their consumption levels affect their energy bills. The primary focus should be on the second factor, as it reflects the gap between peak and average demand. The smaller the second factor, the better, which indicates that customers are contributing less to the system's peak demand. The pricing signal provided by this method is that it is better for consumers to avoid high peak demand and instead to maintain flat and stable energy consumption.

3.4.9. M9: Two-part pricing

The two-part tariff is first proposed in [150]. The first part of the price is linked to marginal cost, the remainder to fixed cost. That is used to recover those costs the marginal-cost-based price is unable. As many studies have shown [108, 111], however, the marginal cost for RESs is almost zero. The ICES considered in this thesis is a grid-independent energy system that only exchanges energy with the grid when necessary, therefore the costs are just a small portion of the total, so we do not take its marginal cost into consideration in the context of this research. Costs in an ICES are mostly fixed, and do not vary with energy generation. In this method, the fixed costs are translated into two parts using a coefficient. One part of cost is considered energy-related and the other part of cost is considered capacity-related. They are then allocated to the end-users based on two charges: an energy charge and a capacity charge. This approach is formulated as:

$$P_E = \frac{TC_E}{\sum_{i=1}^{N} \sum_{t=1}^{T} E_i(t)} \tag{3.21}$$

$$P_C = \frac{TC_C}{\sum_{i=1}^{N} E_{CP,\ i}} \tag{3.22}$$

$$TC = TC_E + TC_C \tag{3.23}$$

$$TC_E = TC \times f \tag{3.24}$$

$$TC_C = TC \times (1 - f) \tag{3.25}$$

where P_E (€/kWh) is average energy price, P_C (€/kW) is coincident peak price. TC_E (€) is the cost allocated to energy component, TC_C (€) is the cost allocated to capacity component, and f is the coefficient that divides the total costs between energy-related and capacity-related costs. The required data items are total costs, hourly energy consumption and peak demand by each household, and a coefficient. The energy bills of end-users are determined by their energy consumption and peak demand. The principle underlying this method is to translate fixed costs into variable ones (energy-related costs) by using a coefficient. These costs are then allocated according to the two cost drivers, energy and capacity, which reflect cost-causality.

3.4.10. M10: Multi-part pricing

This method is derived from cost allocation based on the cost-causality principle. Its name refers to the fact that the system costs are allocated to the agents or elements (also referred to as cost drivers) that cause them, thus giving a highly efficient signal [61, 138]. According to the study reported in [140–142], the most commonly used cost drivers are energy (kWh), capacity (kW), and customer service (customer number). In this approach, the first step is to classify customer service-related costs, which are generated by metering, meter reading, billing, bill collection, and other related activities. The remaining cost is then classified by using a coefficient, which is similar to that used in two-part pricing. The method is formulated as:

$$P_E = \frac{TC_E}{\sum_{i=1}^{N} \sum_{t=1}^{T} E_i(t)} \tag{3.26}$$

$$P_C = \frac{TC_C}{\sum_{i=1}^{N} E_{CP,\ i}} \tag{3.27}$$

$$P_N = \frac{TC_S}{N} \tag{3.28}$$

$$TC_{E+C} = TC_T - TC_S \tag{3.29}$$

$$TC_E = TC_{E+C} \times f \tag{3.30}$$

$$TC_C = TC_{E+C} \times (1 - f) \tag{3.31}$$

Where P_N (€/household/year) is the customer service price, TC_{E+C} (€) is the sum of energy-related and capacity-related costs, and TC_S (€) is the cost of customer service. The required data items are total costs, customer service costs, peak demand, hourly energy consumption, number of households, and allocating coefficient. This approach emphasizes allocating costs to the drivers that cause them, in order to link cost and causality. The costs drivers are reflected in the structure of the final energy bill. This method is easy to implement with the help of smart meters and the pricing strategy is similar to ToU energy pricing either, *ex-ante* or *ex-post*.

3.4.11. Summary of cost allocation methods

Ten methods are introduced in this thesis that can be used to allocate costs in ICESs. Each method has its own characteristics and focuses on different perspectives. Power and energy are the fundamental components in electricity consumption

Table 3.1: Characteristics of cost allocation methods

Cost allocation methods	Pricing component with respect to energy	Pricing components with respect to capacity	Time refelectiveness	Consumption level reflectiveness	Number of charging components
M1: Cost allocation based on the number of users	No	No	No	No	1
M2: Average cost pricing	Yes	No	No	No	1
M3: Time-of-use energy pricing	Yes	No	Yes	No	2
M4: Capacity subscription	No	Yes	No	No	1
M5: Coincident peak	No	Yes	No	No	1
M6: Noncoincident peak	No	Yes	No	No	1
M7: Segmented energy pricing	Yes	No	No	Yes	2
M8: Average and excess method	No	Yes	No	No	2
M9: Two-part pricing	Yes	Yes	No	No	2
M10: Multi-part pricing	Yes	Yes	No	No	3

[81]. Power is the energy consumed per unit of time, and energy is the power consumed over a specific time period [151]. Therefore, the load profile is a function of power and time. Load profiles vary according to customer types, seasons, holidays, and time of the day. At the same time, load profiles have the characteristics of repetitiveness over time. A general household load profile has the characteristic that energy consumption is low during early morning hours and high during late afternoon hours. Peak demand usually happens at night hours. Peak demand occurs only for several hours in a day, while it is the most important influencing factor that makes the cost of the power system high. More generation and network capacity are required to supply the peak demand during peak hours, which are not often used at other times. Therefore, the two fundamental drivers causing costs are energy and peak demand. Time is an external factor indicating that electricity consumption is affected by the time of the day. It is mostly dependent on the energy consumption behaviors of end-users .

In order to reduce the impact of peak demand on the system operation and costs, customers are encouraged to pay attention to both their consumption periods and consumption levels. It is beneficial both to the energy systems and the end-users if they have a relatively flat load profile. It should be noted that the factor of consumption levels is not often used and assessed in many tariff design methods.

The final energy bill structure consists of different charge components. For instance, flat energy pricing includes a single charge component (energy consumption), and two-part energy pricing includes two charge components (energy consumption and peak demand). It reflects how informative the energy bill structure is and can be considered economic signals provided to local community members.

Overall, five items are concluded considering the internal components of load profile and external influencing factors: energy, peak demand (capacity), time reflectiveness, consumption level reflectiveness, and the number of charge components. These influencing factors are summarized in Table 3.1.

3.5. Conclusions

This chapter presents a systemic framework by learning from tariff design in large power systems, in order to ensure a successful implementation of cost allocation in an ICES. The framework identifies the fundamental issues, consists objectives, procedures, required components, and methods, for allocating costs in an ICES. The framework can be considered the guidelines for local communities to follow. This chapter also proposes a number of methods applicable in the context of cost allocation in an ICES. Each has its own characteristics and may perform differently, and there is no consensus on which is the best. It is therefore necessary to evaluate their performance in order to draw clear distinctions between them all. In the next chapter, we study the performance of the methods presented here with a case study.

4

Performance assessment of cost allocation methods

A person who never made a mistake never tried anything new.

Albert Einstein

4.1. Introduction

Ten applicable methods are presented in the previous chapter as the options to allocate costs in ICESs. Their performances vary from one to one due to their different characteristics. There is also no consensus on which method is the best one. It is necessary to have an overall performance of the proposed methods. Cost reflectiveness is the ultimate goal of tariff design no matter in which energy system. A cost-reflective tariff reflects the contribution of consumers to the energy system and incentivizes them to utilize energy in a cost-efficient manner. A cost-predictable tariff helps consumers to estimate the energy bills they have to pay. Thus they have the incentive to take actions to adjust their consumption behaviors.

In this chapter, we address the research sub-question: "How to assess the performance of the cost allocation methods?" The aim of this chapter is to assess to what extent the energy bills paid by local community members reflect the cost they should pay and how the energy bills change in the long-term in terms of the two criteria: cost reflectiveness and predictability. The definition of each criterion is introduced in this chapter. Additionally, we aim to gain an understanding of how the performance of the presented cost allocation methods would perform in terms of the two criteria when situations change. For this purpose, a case study with 100 households is used in the model to investigate the performance of the ten cost allocation methods.

The objectives of the models and relevant equations are formulated and explained in Section 4.2. The performance criteria are defined in Section 4.3. Input data and some assumptions for the case study are outlined in Section 4.4, and the results are analyzed in Section 4.5 and discussed in Section 4.6. Finally, conclusions are drawn in Section 4.7

This chapter is a slightly modified version of the paper "Cost allocation in integrated community energy systems - Performance assessment" submitted to the journal of Applied Energy, which is in press at this moment[143].

4.2. Models of the integrated community energy system

4.2.1. Problem formulation

A model of the ICES is required in order to implement cost allocation. Energy, peak demand, and DER costs are the essential parameters used to allocate the costs to the local community members. For this paper, two such models have been designed: a mathematical and an economic one. The former provides data necessary for cost allocation in the latter, as elaborated below.

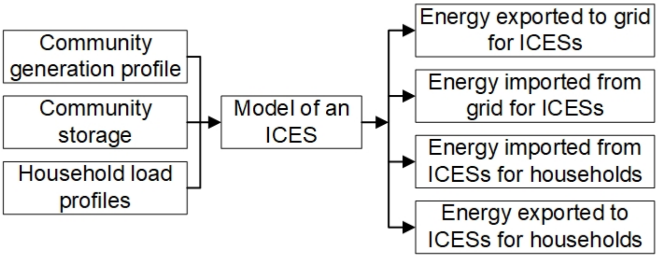

Figure 4.1: Inputs and outputs of mathematical model of the ICES

4.2.2. Mathematical model of the integrated community energy system

The objectives of the mathematical model are: (1) to ensure the balance of energy supply and demand in the ICES; and (2) to calculate the energy data required by the economic model. The inputs and outputs for the mathematical model are shown in Figure 4.1. This model incorporates energy generation, storage, and consumption at the community and the individual household levels.

Load profile of households

Individual households are one of the two fundamental components of an ICES. In our research, the community consists of several households. They can also become prosumers by investing in DERs. The hourly energy demand of each household is denoted as $D_i(t)$ (kWh). A positive value indicates that energy is required from the community, for which the household needs to pay. A negative value indicates that surplus energy is delivered to the community, and from which the household can benefit. The total hourly energy demand by households $D(t)$ (kWh) is:

$$D(t) = \sum_{i=1}^{N} D_i(t) \tag{4.1}$$

Energy generation from renewable energy sources

Energy generation from RESs depends on the installed capacity. The installed photovoltaic (PV) and wind turbine capacities are IC_{PV} and IC_{WT} (kW), respectively. The hourly generated power per capacity from PV and wind turbine is $P_{PV}(t)$ and $P_{WT}(t)$ (kWh/kW), respectively. Therefore, the hourly energy generation from RESs $E_{RES}(t)$ (kWh) is calculated as follows:

$$E_{RES}(t) = IC_{PV} \times P_{PV}(t) + IC_{WT} \times P_{WT}(t) \tag{4.2}$$

Calculating the optimum installed capacity in order to minimize the total costs is usually an optimization problem but not an energy system planning problem, which puts it beyond the scope of this research. Our objective is to allocate costs to customers once the energy system is in place. In this chapter, we use the following rule to calculate installed capacity: the yearly energy generation from RESs equals the yearly energy demand. In practice, however, energy generation from RESs may not be enough to meet demand at all times. And there are also periods when energy generation exceeds demand. The hourly energy difference $E_{dif}(t)$ (kWh) is calculated as:

$$E_{dif}(t) = E_{RES}(t) - D(t) \tag{4.3}$$

Energy storage

Energy storage is used to retain surplus energy from generation for later supply to households when there is a shortage from generation. Energy generated by RESs is first delivered to households, then the surplus generation is transferred to storage. Once the storage system is full, any further surplus is sold to the grid to earn revenue. When generation by RESs falls short of current demand, stored energy is used first to make up the shortfall. When that runs out, the community energy system purchases the extra energy it needs from the grid. The energy state of the battery always satisfies the following formula:

$$E_B(t+1) = \begin{cases} E_{Bmax} & E_B(t) + E_{dif}(t) \times B_e \geq E_{Bmax} & (4.4a) \\ E_B(t) + E_{dif}(t) \times B_e & E_{Bmin} < E_B(t) + E_{dif}(t) \times B_e < E_{Bmax} & (4.4b) \\ E_B(t) + E_{dif}(t)/B_e & E_{Bmin} < E_B(t) + E_{dif}(t)/B_e < E_{Bmax} & (4.4c) \\ E_{Bmin} & E_B(t) + E_{dif}(t)/B_e \leq E_{Bmin} & (4.4d) \end{cases}$$

where $E_B(t+1)$ and $E_B(t)$ (kWh) is the energy state of the storage system at hours $t+1$ and t, respectively, E_{Bmax} and E_{Bmin} (kWh) are its maximal and minimal energy state, and B_e is its charging and discharging efficiency.

Following the energy system operation rule, it is easy to calculate the energy exchange with the grid for the whole community. The hourly energy exchange with grid $E_{ex,\ grid}(t)$ (kWh) is as follows:

$$E_{ex,\ grid}(t) = \begin{cases} E_{dif}(t) - (E_{Bmax} - E_B(t))/B_e & E_B(t) + E_{dif}(t) \times B_e \geq E_{Bmax} & (4.5a) \\ 0 & E_{Bmin} < E_B(t) + E_{dif}(t) \times B_e < E_{Bmax} & (4.5b) \\ 0 & E_{Bmin} < E_B(t) + E_{dif}(t)/B_e < E_{Bmax} & (4.5c) \\ E_{dif}(t) + (E_B(t) - E_{min}) \times B_e & E_B(t) + E_{dif}(t)/B_e \leq E_{Bmin} & (4.5d) \end{cases}$$

4.2.3. Economic model of the integrated community energy system

The economic model aims to calculate the annualized energy cost for the whole community, in order to facilitate cost allocation during the next step. The inputs and outputs of the economic model are presented in Figure 4.2. The annual energy costs at the community level include the annualized cost of DERs, which consist of capital costs, O&M costs, and other costs caused mainly by providing customer

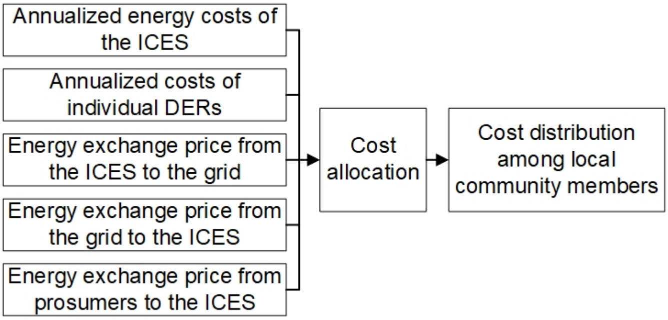

Figure 4.2: Inputs and outputs of economic model of the ICES

services. These costs are typically fixed. Energy exchange prices between the ICES and the grid determine the energy exchange costs, which generally vary with the amount of energy exchange. The annualized costs are then allocated according to the method selected by the local stakeholders.

4.3. Assessment criteria

4.3.1. Cost reflectiveness

No matter what energy system is used, the ultimate goal of cost allocation is cost reflectiveness. This topic has been addressed in many studies [62, 144]. A cost-reflective allocation mirrors the contribution made by consumers to the energy system and incentivizes them to utilize energy in a cost-efficient manner. In order to evaluate how close the energy bills actually paid by local community members in the ICES are to the amounts they should be paying, the cost of investing in DERs by the individual is used as the benchmark to indicate whether the specific cost allocation method is cost-reflective. To provide a quantitative method to measure cost reflectiveness, in this thesis, it is defined as the ratio of the difference between the cost local community members pay in the ICES and the cost of their own investments in DERs, divided by that latter investment cost. Cost reflectiveness is expressed as follows:

$$CRI_{i,j} = \frac{C_{i,j} - C_{i,DER}}{C_{i,DER}} \tag{4.6}$$

where $CRI_{i,j}$ is the cost reflectiveness index for household i under method j, $C_{i,j}$ (€) is the annual cost to household i based on the method j, and $C_{i,DER}$ (€) is the annual energy costs to household i of its individual energy system, including investments in DERs and the costs of energy exchange with the grid. If the result is positive, it indicates that the household is paying more than it should. Zero means that it is paying exactly the right amount and a negative result indicates it is paying less and so saving on its energy bills by being part of the ICES. It also indicates that the household benefits from its ICES participation, compared to investing individually in DERSs.

4.3.2. Cost predictability

A sustained commitment by local community members is an essential factor that affects the long-term development of ICESs, and that commitment is greatly influenced by the way their energy bills evolve. Customers will leave the energy system if their energy costs increase a lot year on year, and that is likely to trigger a vicious circle of ever-higher bills forcing out more and more customers. Which, eventually, will lead to a complete collapse of the energy system. As for investors, their objective is to ensure cost recovery. Cost predictability helps them evaluate the extent to which they can do this. For this reason, it is necessary to compare the long-term differences in energy bills.

Cost predictability is all about changes in energy bills [62]. Local community members can evaluate if the selected method provides a long-term incentive by comparing their energy costs in two consecutive years. If the change is small or close zero, it indicates that the selected method provides a strong long-term incentive. It is thus a good indicator that local members will remain in the ICES in the long-term. It also contributes to the stable development of the energy system. In this thesis, cost predictability is defined as the difference between costs in two consecutive years, formulated as:

$$CPI_{i,j} = \frac{C2_{i,j} - C1_{i,j}}{C1_{i,j}} \tag{4.7}$$

where $CPI_{i,j}$ is the cost predictability index for household i under method j, and $C1_{i,j}$ and $C2_{i,j}$ (€) are its energy costs in years 1 and 2 under method j, respectively. A positive result indicates that the household pays more in the second year, zero that it pays the same in both years, and a negative value that it pays less in the second year. Ideally, any difference should be minimized so that the amount of the household's annual energy bill does not change much over the lifetime of the energy system. That attracts customers to stay in the ICES in the long-term.

4.4. Case study: Data & assumptions

This case study investigates the performance of cost allocation methods in respect of cost reflectiveness and predictability for a group of 100 households. This section explains the background of the input data.

4.4.1. Hourly energy demand

The case study makes use of household electricity consumption data from the UK Power Networks project (half-hourly measurements over two years in 2012 and 2013) [152].

Table 4.1: Techno-economic parameters

	Capital costs (€/kW)	O&M costs (€/kW/year)	Lifetime (years)	Source
PV	1100	5.5	25	[154]
Battery	200	2	10	[155]

Table 4.2: Energy exchange prices

	From the grid to ICES	From ICES to the grid	Households to ICES
Energy exchange price (€/kWh)	0.21	0.10	0.10

4.4.2. Hourly PV power generation

For this case study, the only RESs taken into consideration are PV panels in the local community. The hourly metered data for RES generation is obtained from the open data platform Renewables.ninja [153].

4.4.3. Techno-economic parameters

Table 4.1 presents the techno-economic parameters used in the case study. They include capital costs, O&M costs, and the lifetimes of the PV panels and battery. Table 4.2 shows the energy exchange prices between the different parties: from the grid to the ICES, from the ICES to the grid, and from households to the ICES.

4.5. Case study: Results analysis

4.5.1. Analysis of cost reflectiveness

The results of the calculations of cost reflectiveness for the ten cost allocation methods are shown below. Figure 4.3 shows the probability density of the distribution of cost reflectiveness under the ten cost allocation methods for a group of 100 households consuming electricity in an ICES. These distributions indicate how cost-reflective a cost allocation method is. For each sub-figure, a higher peak around zero indicates more consumers with perfect cost reflectiveness, while a thinner tail near the horizontal axis indicates that fewer consumers are paying more or less than they should be. These are desirable characteristics for the cost allocation methods. In order to gain more insight into the results, the median, the variance, and the 5^{th} and 95^{th} percentile values of the distribution are also calculated, these are listed in Table 4.3.

From Table 4.3 and Figure 4.3, a number of conclusions can be drawn. First of all, the ten cost allocation methods all have a median value less than zero, which implies that the majority of the consumers pay less in the ICES than if they were to invest individually. Secondly, methods 2 and 4 have the lowest variance (equal

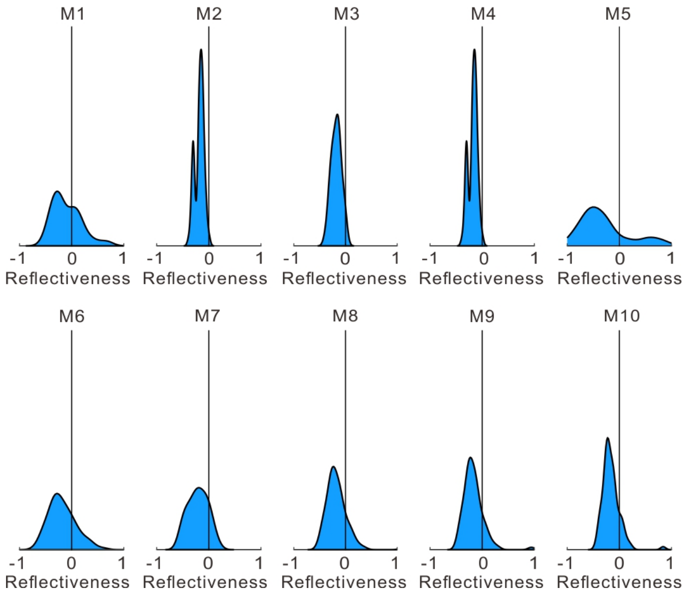

Figure 4.3: Probability density of the distribution of cost reflectiveness under the ten cost allocation methods for households

Table 4.3: Descriptive statistics for cost reflectiveness under different cost allocation methods

	M1	M2	M3	M4	M5	M6	M7	M8	M9	M10
Median	-0.183	-0.165	-0.171	-0.165	-0.391	-0.212	-0.206	-0.206	-0.199	-0.194
Variance	0.075	0.007	0.010	0.007	0.508	0.110	0.035	0.047	0.037	0.029
5^{th} percentile	-0.500	-0.340	-0.350	-0.340	-0.910	-0.590	-0.550	-0.460	-0.440	-0.390
95^{th} percentile	0.470	-0.050	0.000	-0.050	1.120	0.360	0.130	0.190	0.150	0.110

in this case), and both the 5^{th} and 95^{th} percentile values are closest to zero. This implies that these two methods are the most cost reflective of the ten cost allocation methods. Methods 2 and 4 have the same performance because the subscribed capacity in method 4 is calculated by dividing annual energy consumption by annual generation per capacity. This means that energy bills are determined by the volume of electricity consumption, which is the same strategy as used in method 2. Method 3's performance is comparable to that of method 2 (or 4); they have the same pricing mechanism, with charging for the energy component, although method 3 also considers time differences. Method 5 shows the poorest cost reflectiveness since it has the highest variance: about 5% of consumers are paying 91% less than what is considered cost-reflective and about 5% of are paying 112% more. The reason for this bad performance is that coincident peak pricing allocates costs based on the peak demand contribution by each consumer to the total system peak demand, even though these two peaks do not always coincide. Method 10 performs similarly to method 9, but slightly better. It subdivides total costs into three components - those related to energy, capacity, and customer services, respectively. Whereas method 9 is confined to two-part pricing, with only energy and capacity components.

4.5.2. Analysis of cost predictability

Cost predictability is another essential factor that affects the performance of cost allocation methods. Local community members can predict the extent to which their energy bills change year on year. And investors can predict the extent to which they are likely to recover their investment. As with cost reflectiveness above, Figure 4.4 shows the probability density of the distribution of cost predictability under the ten cost allocation methods for a group of 100 households consuming electricity in an ICES in two consecutive years. Moreover, the median, the variance, and the 5^{th} and 95^{th} percentile values of the distribution are also calculated; these are shown in Table 4.4. Method 1, allocating costs based on the number of users, is omitted as its predictability is perfect. The reason for this is that the annual costs to be recovered consist of two parts: fixed costs for DERs, which are the same each year, and variable costs for energy exchange with the grid and the household. The variable costs are determined by the volume of energy exchanged and the energy exchange price. In this case study, the ICES is grid-connected, but for the most part independent of the grid, since the great majority of the energy consumed comes from community generation. The energy exchange costs in years 1 and 2 are € 13442 and € 14148, respectively. In other words, there is almost no change in costs and so the cost predictability of method 1 is assumed to be perfect.

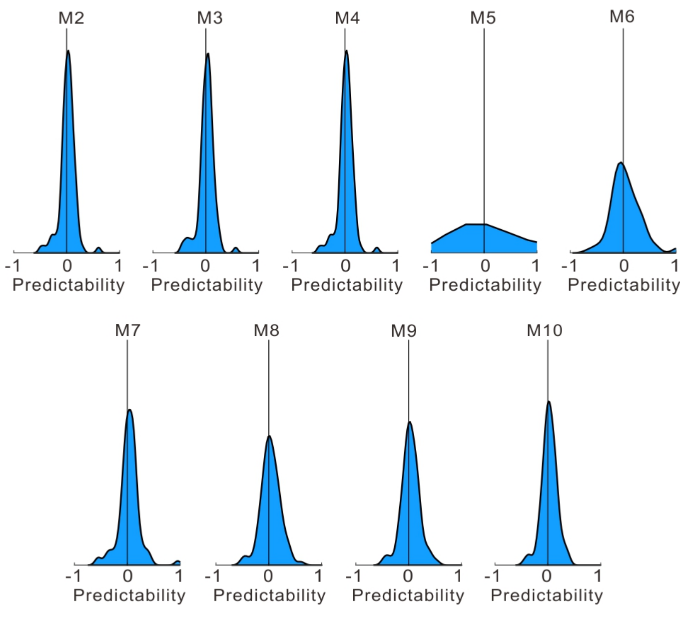

Figure 4.4: Probability density of the distribution of cost predictability under the ten cost allocation methods for households

Table 4.4: Descriptive statistics for cost predictability under different cost allocation methods

	M1	M2	M3	M4	M5	M6	M7	M8	M9	M10
Median	-	0.027	0.029	0.027	0.056	0.017	0.035	0.022	0.034	0.031
Variance	-	0.032	0.033	0.032	14.104	0.216	0.055	0.073	0.058	0.036
5^{th} percentile	-	-0.260	-0.280	-0.260	-0.910	-0.370	-0.320	-0.270	-0.250	-0.220
95^{th} percentile	-	0.220	0.230	0.220	2.000	0.580	0.350	0.380	0.360	0.300

From Table 4.4 and Figure 4.4, we can draw the following conclusions. The differences between the ten methods are apparent. They can be classified into two categories. In the first of these, methods 5 and 6 have a lower peak around zero and a fatter tail, which indicates that a substantial year-on-year change in energy bills is more likely. This can also be seen from the percentile values in Table 4.4. In the second category are the remaining methods, all with a high peak around zero, indicating that their cost allocations in the two consecutive years remain constant for many customers in the local community. This high predictability also shows up in Table 4.4 for these methods: their median and variance values are close to zero. Methods 2 and 4 produce the same performance, for the same reason as they do with cost reflectiveness. Methods 2, 3, 4, and 10 all have a similar, better performances, with a lower variance, the median near zero, and both their 5^{th} and their 95^{th} percentile values closest to zero. Methods 7, 8, and 9 display performances comparable to methods 2, 3, 4 and 10. A method includes an energy charging component shows a better performance with respect to cost predictability.

4.5.3. Abnormal conditions analysis

In the cases above, community energy generation and consumption in the second year do not change significantly. It is easy to conclude that each method has a similar performance in different years in the lifetime of the energy system, since the common costs of community DERs are fixed and energy exchange costs accounts for a small portion of total common costs. The cases analyzed above are in an ideal and normal situation, however, it is also interesting to see how cost reflectiveness and predictability might change following a sudden change in energy generation and consumption. A comprehensive analysis has therefore been carried out to do just that. For this, it is assumed that both energy generation from solar panels and household consumption either increase or decrease by one-third in the second year, in this case study, that is the year 2013 - thus producing four scenarios for the analysis of each indicator. The corresponding results in terms of the probability density of the distribution of cost reflectiveness and of cost predictability for the ten methods are shown in Figures 4.5 and 4.6, respectively.

From these two figures, it is apparent that both cost reflectiveness and predictability decline in abnormal conditions, no matter which method is applied. The effect of energy generation increasing and energy consumption decreasing shows a similar performance, which is the same for the case of energy generation decreasing

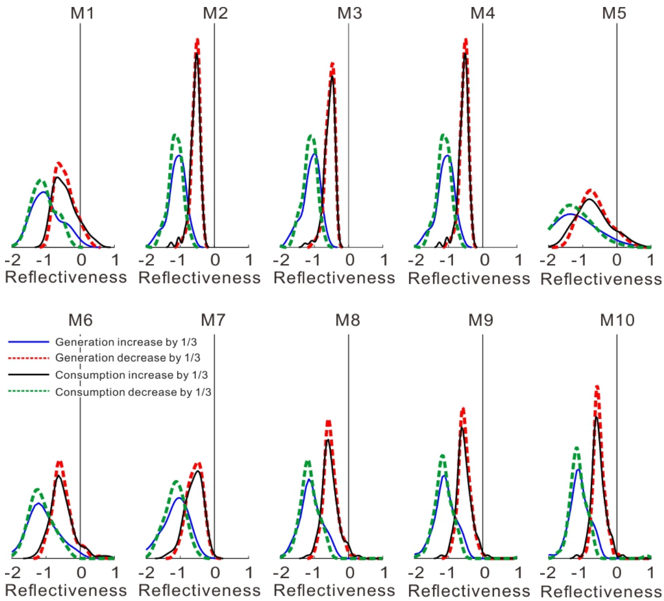

Figure 4.5: Probability density of the distribution of cost reflectiveness under the ten cost allocation methods for households in abnormal conditions

and energy consumption increasing. Furthermore, local communities pay less in the case that energy generation increasing and consumption decreasing. This can be explained by the fact that when energy generation increases or consumption decreases, there is a surplus generation in the energy system. The ICES and the local community members then benefit from selling surplus energy to the grid and the ICES. However, local community members pay more in the case of energy generation decreasing and consumption increasing, compared to when energy generation increases and consumption decreases. In this case study, the majority of local community members pay less compared to the costs they should pay or their energy bills in the year before.

From the analysis in Section 4.5.1, Section 4.5.2 and this section, it can be concluded that cost reflectiveness and predictability only retain their merits if changes are minor; these merits evaporate in the event of significant sudden changes in generation and consumption. For this reason, the cost allocation results should remain more or less the same in the short-term and only gradually change in the long-term.

4.5.4. Sensitivity analysis

It is also essential to see how cost allocation would perform in terms of the two criteria, cost reflectiveness and predictability, in the event of a change in the number of consumers taking part in the ICES. A sensitivity analysis for the ten cost allocation methods in that scenario has therefore been conducted. Figures 4.7 and 4.8 show

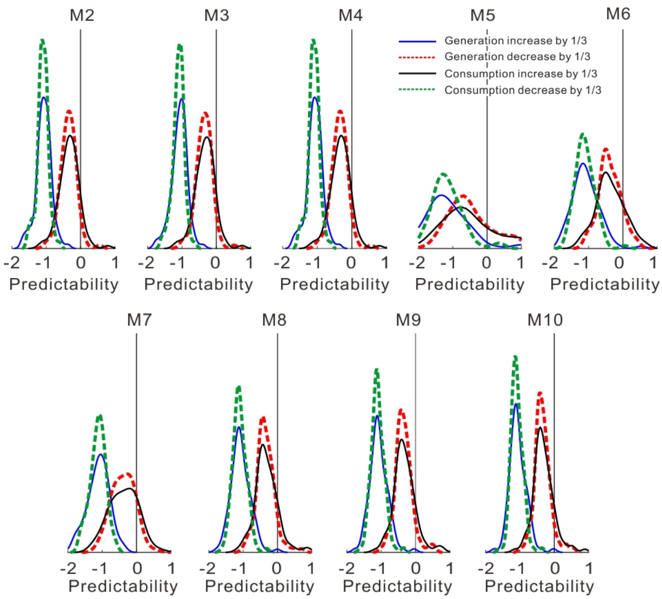

Figure 4.6: Probability density of the distribution of cost predictability under the ten cost allocation methods for households in abnormal conditions

the probability density of the distribution of cost reflectiveness and predictability for the ten cost allocation methods with 20, 50, and 80 consumers in the ICES. From the results in this regard, it can be concluded that there is almost no change in the distribution profile of the two criteria. This implies that the number of consumers has little or no influence on the performance of the ten cost allocation methods in terms of cost reflectiveness and predictability. In other words, this sensitivity analysis demonstrates that the performance of a cost allocation method is not dependent on the size of the community.

4.5.5. Cost allocation with different number of prosumers

Another essential aspect to look at is how well the cost allocation methods would handle changes in the roles of local community members. With a higher percentage of prosumers in the ICES, energy consumption changes and energy sharing by those prosumers increases. An effective cost allocation method should retain its merits, cost reflectiveness and predictability, under such changing condition. To gain an insight into how cost reflectiveness and predictability change, the ten cost allocation methods have been assessed with 30%, 60%, and 100% penetration of prosumers in the ICES. In this model, the 100 households are randomly assigned to be prosumers. The installed capacity of DERs follows the same rule that annual generation from DERs equals annual consumption. The resulting cost reflectiveness with different percentages of prosumers for the ten methods is shown in the form of probability densities in Figure 4.9 and the relevant statistics are provided in Table 4.5.

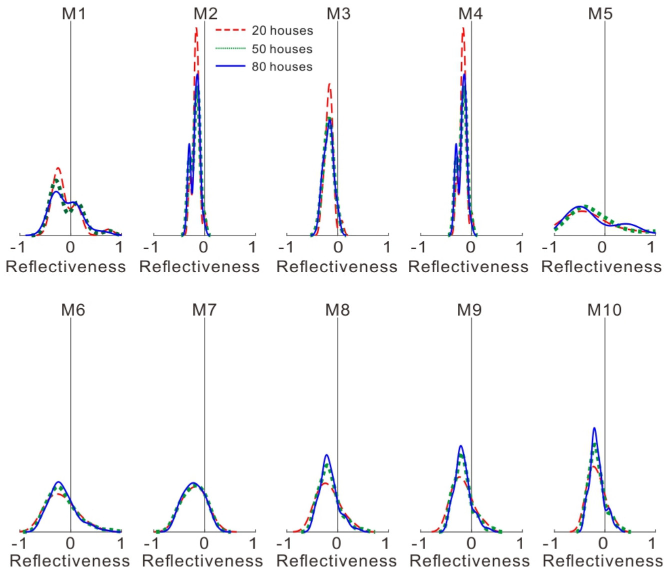

Figure 4.7: Probability density of the distribution of cost reflectiveness under the ten cost allocation methods with different numbers of consumers

From figure 4.9, it is clear that cost reflectiveness increases in line with the rise in the percentage of prosumers. Cost reflectiveness increases a little or remains more or less the same when the penetration of prosumers rises from 30% to 60%, but there is a significant increase when that figure rises from 60% to 100%. This is easy to explain, since prosumers pay for their own investment in DERs. Methods 1, 5 and 6 have by far the lowest reflectiveness, which can be explained by their special pricing mechanisms. The common costs (annual community energy costs) are allocated evenly in method 1 and based on coincident and non-coincident peak demand in methods 5 and 6, meaning that prosumers may pay for costs they have not actually incurred. In case of methods 2, 3, 4, and 7, the peak of the reflectiveness distribution increases substantially with the increasing penetration of prosumers, an outcome consistent with the statistics shown in table 4.5.

The same analysis has also been done for cost predictability. The results for the ten cost allocation methods with different percentage of prosumers are shown in Figure 4.10, and relevant statistics can be found in Table 4.6. From the figure, it can be seen that cost predictability when using methods 2, 3, 4, and 7 remains more or less the same as prosumer penetration increases. This can be explained by the fact that charging with these four methods is based on a single pricing component, namely energy. Furthermore, the annual costs to be recovered do not change much since the prior assumption is that the annual costs of community DERs are the same throughout the life-time of the energy system and the only variable costs are for energy exchange. The costs allocated to local community members will thus not change much, even though their energy consumption increases. For the

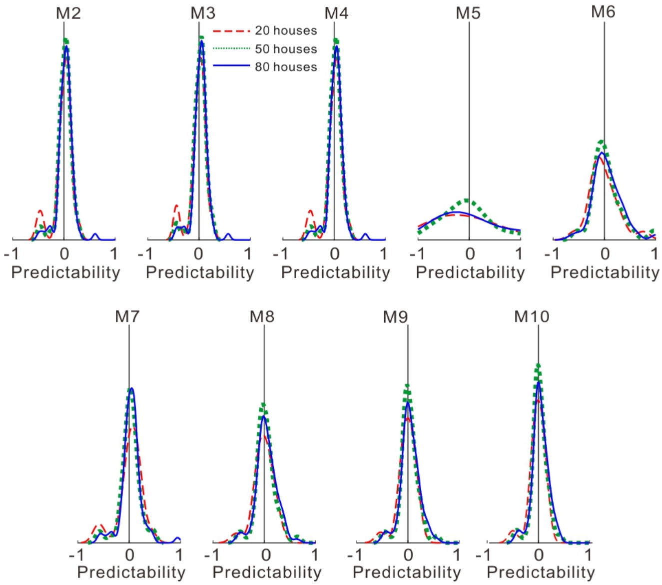

Figure 4.8: Probability density of the distribution of cost predictability under the ten cost allocation methods with different numbers of consumers

remaining methods, the peak of the predictability distribution rises with the increase in prosumer penetration. This can be explained by the fact that the prosumers pay for their own individual investments in DERs. Moreover, these methods have either a capacity component only or a combination of energy and capacity components. From thee findings we can conclude that the increasing prosumer penetration has a positive effect on cost predictability, which also indicates that the possibility of cost recovery is improved.

4.6. Discussions

The cost allocation methods described in this chapter all have their own characteristics. They have different charging components (energy, capacity, or the number of users), and they take different factors into account (time and consumption level differences, and so on). And they show different performances with regard to different criteria. It is not easy to satisfy all the requirements at the same time. The case study presented in this chapter has assessed the performance of the ten methods in terms of cost reflectiveness and predictability. From the analysis of the results, we can conclude that methods with energy as their single charging component perform better than either those with capacity as their sole component or those allocating costs based on the number of users in terms of cost reflectiveness and predictability. Cost reflectiveness increases with the increasing number of prosumers, while cost predictability remains more or less the same. Methods with energy and capacity-based charging components show comparable performance to the solely energy-based

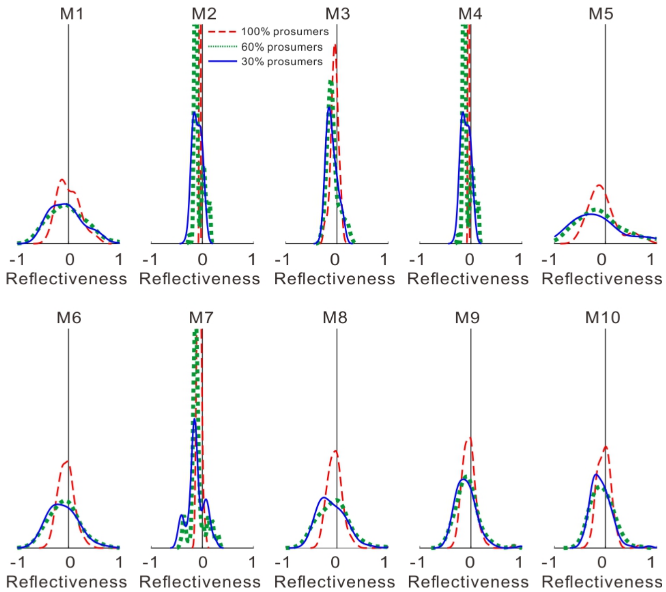

Figure 4.9: Probability density of the distribution of cost reflectiveness under the ten cost allocation methods with different percentages of prosumers in the ICES

methods. It is easy to explain that methods with just energy components are a measure of average demand and that the installed capacity of DERs is based on their generation capacity. Peak demand, meanwhile, is dependent on a single moment in the year and differs year on year. Therefore, peak demand-based methods show a lower cost reflectiveness and predictability.

From the consumer perspective, cost reflectiveness is far more important as the costs allocated to them should be in line with the amount of energy they consume. For investors, however, cost predictability is more important, to help ensure that they recover their costs. According to the analysis above, energy-based methods are the most desirable if both of these metrics are to be satisfied. Moreover, those methods with both energy and capacity components are the second-most desirable. The different energy-based methods display similar performances, but each emphasizes different aspects. For this reason, it is not easy to provide a definitive solution regarding the ideal cost allocation method to select based on the quantitative analysis in this chapter. The opinions of local community members play an essential role in that process, and they inevitably have different educational backgrounds and, my well hold different points of view regarding the various methods. Some, for instance, may prefer to choose a method with a single charging component over a more complex one with more or less the same performance. Moreover, this paper focuses only on the analysis of cost reflectiveness and cost predictability, while other criteria such as cost causality (revealing cost drivers) and time difference will also affect local community members' opinions. In practice, it is therefore critical that those opinions be taken into account and that a method be selected that is socially

Table 4.5: Descriptive statistics of cost reflectiveness under the ten cost allocation methods with different percentages of prosumers

	M1	M2	M3	M4	M5	M6	M7	M8	M9	M10
30% prosumers										
Median	-0.053	-0.106	-0.121	-0.106	-0.200	-0.113	-0.141	-0.143	-0.112	-0.109
Variance	0.111	0.008	0.011	0.008	0.302	0.114	0.028	0.080	0.046	0.041
5^{th} percentile	-0.550	-0.260	-0.270	-0.260	-0.900	-0.590	-0.430	-0.520	-0.410	-0.390
95^{th} percentile	0.620	0.060	0.110	0.060	1.070	0.480	0.160	0.410	0.280	0.260
60% prosumers										
Median	-0.037	-0.122	-0.108	-0.122	-0.146	-0.089	-0.123	-0.072	-0.077	-0.085
Variance	0.115	0.008	0.015	0.008	0.206	0.102	0.020	0.084	0.048	0.045
5^{th} percentile	-0.600	-0.170	-0.250	-0.170	-0.780	-0.580	-0.350	-0.560	-0.420	-0.420
95^{th} percentile	0.620	0.120	0.180	0.120	0.850	0.500	0.210	0.460	0.320	0.330
100% prosumers										
Median	-0.037	-0.122	-0.108	-0.122	-0.146	-0.089	-0.123	-0.072	-0.077	-0.085
Variance	0.046	0.000	0.006	0.000	0.088	0.037	0.002	0.032	0.023	0.019
5^{th} percentile	-0.330	-0.060	-0.200	-0.060	-0.470	-0.300	-0.130	-0.270	-0.240	-0.240
95^{th} percentile	0.440	-0.030	0.080	-0.030	0.610	0.270	0.020	0.240	0.200	0.200

Table 4.6: Descriptive statistics of cost predictability under the ten cost allocation methods with different percentages of prosumers

	M1	M2	M3	M4	M5	M6	M7	M8	M9	M10
30% prosumers										
Median	-	0.031	0.034	0.031	0.077	0.020	0.032	0.018	0.019	0.022
Variance	-	0.032	0.033	0.032	10.931	0.069	0.049	0.040	0.033	0.023
5^{th} percentile	-	-0.260	-0.290	-0.260	-0.810	-0.340	-0.330	-0.280	-0.250	-0.220
95^{th} percentile	-	0.220	0.230	0.220	2.000	0.460	0.300	0.350	0.350	0.300
60% prosumers										
Median	-	0.035	0.037	0.035	0.076	0.036	0.043	0.038	0.041	0.037
Variance	-	0.028	0.031	0.028	0.622	0.048	0.039	0.033	0.027	0.019
5^{th} percentile	-	-0.250	-0.260	-0.250	-0.730	-0.290	-0.290	-0.250	-0.220	-0.190
95^{th} percentile	-	0.240	0.270	0.240	1.650	0.400	0.300	0.330	0.310	0.250
100% prosumers										
Median	-	0.041	0.040	0.041	0.070	0.048	0.044	0.047	0.045	0.041
Variance	-	0.031	0.034	0.031	0.252	0.023	0.035	0.019	0.018	0.011
5^{th} percentile	-	-0.240	-0.270	-0.240	-0.490	-0.160	-0.260	-0.140	-0.140	-0.110
95^{th} percentile	-	0.270	0.300	0.270	1.200	0.290	0.300	0.270	0.260	0.210

acceptable to the local community.

According to the abnormal condition analysis, furthermore, the methods addressed here are unable to deal well with sudden changes in energy generation and

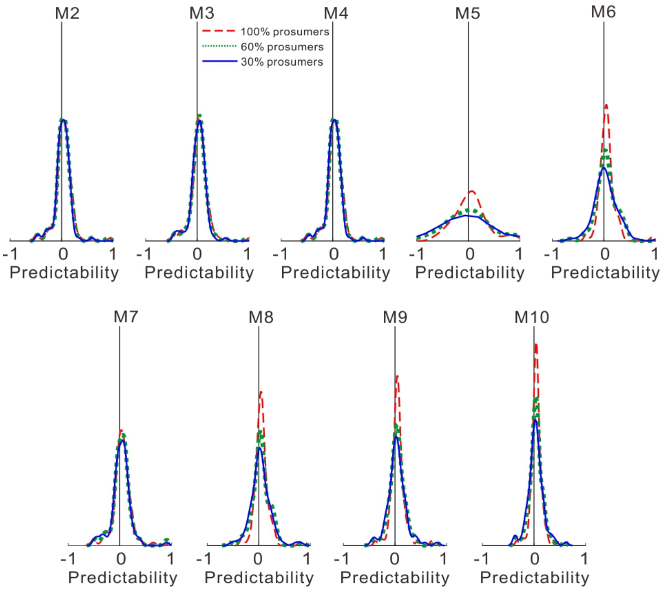

Figure 4.10: Probability density of the distribution of cost predictability under the ten cost allocation methods with different percentages of prosumers in the ICES

consumption. Their metrics in terms of cost reflectiveness and predictability are rendered useless in those circumstances. However, the results do still show that the majority of local community members still benefit from joining an ICES, even under such abnormal conditions: they pay less compared to investing in DERs themselves. In normal conditions, meanwhile, the cost allocation methods we present display stable performance in terms of cost reflectiveness and predictability. In this study, the community under consideration is small in scale. According to the sensitivity analysis, however, the methods retain their performance even when the size of the community changes - a desirable characteristic. Furthermore, the ten cost allocation methods can well handle the changes in the roles of local community members from consumers to prosumers in terms of the two criteria. Overall, then, the analyses carried out in this chapter help us to understand the performance of cost allocation methods.

4.7. Conclusions

Cost reflectiveness and predictability in cost allocation are favored merits, no matter what the energy system is. These are the key characteristics ensuring that cost allocation is fair and acceptable. The performance in terms of those factors of the methods presented in the previous chapter has been assessed based on a case study in this chapter. The results show that energy-based allocation methods perform better, they reflect the costs the users should pay. Moreover, their energy bills are stable and predictable when there are only gradual changes in energy generation and consumption. Furthermore, the energy-based allocation methods retain their merits in respect of the two criteria in the event of changes in the number of local community members and prosumers. These results verify the robustness of the cost allocation methods presented here, while the comprehensive analysis in this chapter provides a better understanding of their performance. Since local communities are not subjected to statutory regulation, their members need to support the method used to allocate costs in the ICES. For this reason, their opinions should be considered carefully before selecting a method that is socially acceptable to them. Therefore, a social acceptance analysis is carried out in the next chapter.

5

Social acceptance analysis of cost allocation in ICESs

Let life be beautiful like summer flowers and death like autumn leaves.

Rabindranath Tagore

5.1. Introduction

In large power systems, the regulator makes decisions on tariff design according to the regulatory principles. However, no regulators are dealing with these issues in ICESs. One of the novel aspects of ICESs lies in the integration of local community members and local DERs [22]. Local coommunity members play an important role in the energy system by actively involving in the planning, development, and administration of the energy system as well as the allocation of its costs and benefit. Local community members are encouraged to participate in the decision-making process. In addition, they may have different situations in, such as educational background, employment, financial issues, skills, experience, personality, energy demand, etc.. [156, 157]. Therefore, they may have various preferences towards cost allocation. The selected cost allocation method should satisfy the requirements and preferences of local community members. And the community itself needs to agree on the cost allocation method themselves. It, therefore, requires that the selected cost allocation method be socially acceptable to local stakeholders. Studies in this area are often missing. Therefore, it is necessary to review the topic of social acceptance in relevant areas to see what lessons can be learned and how they can be applied in the context of cost allocation in ICESs.

This chapter aims to formulate a framework to help the local community to make a decision on selecting a socially acceptable cost allocation method by taking their opinions and preferences into account. Firstly, social acceptance is required to be conceptualized in the context of cost allocation in ICESs, to make sure both the process and the results of cost allocation are fair and socially acceptable to local community members. Secondly, the decision-making on selecting a socially acceptable cost allocation method is required to consider from a multi-group multi-criteria decision-making perspective.

In this chapter, we address the research sub-questions: "How to select a socially acceptable cost allocation method ?". We start with a review on the social acceptance analysis in renewable energy projects and multi-criteria decision-making for multi-group decision-making in Section 5.2 to derive the essential knowledge for conceptualizing social acceptance. In section 5.3, social acceptance is conceptualized from the perspective of procedural and distributive justice. Then the performance of the ten cost allocation methods presented in this thesis is evaluated in terms of the criteria affecting social acceptance in Section 5.4. Section 5.5 introduces the multi-criteria decision-making methodology, and the results are presented in 5.6. Discussions and relevant policy implications are provided in Section 5.7. Finally, the conclusions are drawn in Section 5.8

This chapter is a slightly modified version of the paper "Cost allocation in integrated community energy systems - social acceptance" published in the journal of Sustainability [55].

5.2. Social acceptance: theoretical background

5.2.1. Social acceptance in renewable energy projects

A growing number of literature has addressed the issue of social acceptance of renewable energy technologies, especially wind energy [158–160]. These studies investigate the factors that affect social acceptance of wind energy projects by using empirical studies from various aspects: social perspective [161], economic and financial perspective [162], and ownership perspective [163]. The original conceptualization of social acceptance of renewable energy innovation is introduced by [164] and three dimensions are addressed: social-political, market, and community acceptance. Social-political acceptance refers to the acceptance of technologies, policies, and institutional changes by key stakeholders and policy actors [165]. Market acceptance reflects the acceptance of various stakeholders (consumers, investors, and other relevant stakeholders) in the commercialization process of the project [164]. Community acceptance addresses the issue to what extent the decisions are acceptable to local stakeholders, residents, and local authorities of the local-based projects [166].

Community acceptance is mainly addressed in the study on social acceptance of renewable energy projects among the three dimensions (social-political, market, and community acceptance) [167, 168]. The factors that are mainly influencing community acceptance are distributive justice and procedural justice [164, 169]. Distributive and procedural justice are also widely used in the study of energy justice to guarantee fair and equitable access to resources and technologies in the process of the energy transition [170–172]. Distributive justice focuses on how the costs and benefits are distributed fairly, which is the critical factor to support the implementation of the projects [173]. It is generally used to evaluate the fairness of the outcomes [174, 175]. The study in [176] analyzes the factors that affect the distributive justice on wind projects (fair distribution of the benefits and burdens of wind energy projects) by means of interviews among local citizens. Procedural justice focuses on the process of decision-making, it requires that all the stakeholders are treated in a non-discriminatory manner [177]. It states that all the stakeholders should be able to participate in the decision-making process equitably, and their points of view are taking into consideration thoroughly [166]. Furthermore, it demands that all the stakeholders are accessible to all the relevant information. Procedural justice is essential to increase community acceptance [158]. Both procedural and distributive justice are addressed in the analysis of community acceptance of wind energy projects by [169]. Three levels of engagement: information, consultation, and participation are analyzed for procedural justice, and financial participation of local citizens and other stakeholders are analyzed for distributive justice. In summary, the study of social acceptance of renewable energy projects is mostly focused on the community acceptance dimension in terms of the two key aspects: distributive and procedural justice. In the context of cost allocation in ICESs, the objective is to allocate costs in a socially acceptable manner by taking local community members' opinions into account. Both the process and the results of cost allocation should be fair and acceptable to local community members in ICESs. Therefore, the analysis of social acceptance should start from the dimension of community acceptance by taking the two aspects of procedural and distributive justice into account, which is most relevant to this research. It is essential to define proper criteria that affect procedural and distributive justice, which will be further discussed in the following part of this research.

Besides, many methods can be used to allocate costs in ICESs, which have been extensively explained in Chapter 3.4. Each cost allocation method has different performance over various criteria, such as cost causality and cost reflectiveness [46, 47]. Local community members have various preferences over these criteria. Some may prefer that the costs are allocated to the drivers that made it, while others may prefer to pay the energy bills that reflect the cost they should pay. There is no consensus on which is the best cost allocation method. Local community members need to agree on the approach, which can satisfy their preferences to the most, thus socially acceptable to them. Furthermore, local community members with similar backgrounds and interests may have similar or the same preference over the criteria. Therefore, they can be classified into several groups according to their major preferences. It, therefore, stands for a multi-group, multi-criteria, and decision-making problem. The method that can handle this problem is multi-criteria decision-making (MCDM), which can take the preferences of all the stakeholders into account and further assist their decision-making (select a cost allocation method). Therefore, MCDM methods for dealing with multi-group decision-making will be introduced in the next section.

5.2.2. Multi-criteria decision-making in multi-group decision-making

MCDM techniques are considered an effective tool for supporting decision-makers to take decisions while considering all the criteria and objectives simultaneously with multiple alternatives [178, 179]. In general, the criteria and objectives are conflicting, therefore, the solution of the decision-making problem highly depends on the interests and preferences of the decision-makers [180]. MCDM techniques have been applied substantially on the subjects of evaluating and comparing sustainable and renewable energy options [181, 182], energy storage options [183, 184], energy planning [157, 185], and energy policies [186, 187]. MCDM techniques are used to compare the performance of each option with certain criteria. The criteria considered cover many aspects from technical, economic, social, institutional to environmental perspectives [188]. The option that is ranked with the highest score is deemed to be the best choice for the considered MCDM problem [189].

The reviews of [185] and [188] give good overviews of earlier studies on MCDM in the application of sustainable energy decision-making. The commonly used methods for multi-group decision-making are analytic hierarchy process (AHP), elimination et choice translating reality (ELECTRE), preference ranking organization method for enrichment evaluation (PROMETHEE), and technique for order preference by similarity to ideal solution (TOPSIS). AHP method decomposes the decision-making problem into a hierarchy problem with the goal in the top layer, criteria in the middle level, and alternatives at the bottom layer [190]. It selects the alternative based on pair-wise comparison according to the expert judgments [191, 192]. ELECTRE and PROMETHEE methods rank the alternatives by utilizing the outranking relation between alternatives based on pair-wise comparisons [193, 194]. TOPSIS is a useful technique for the application of MCDM problems in a group decision-making environment to select a suitable alternative [195, 196]. It considers both the positive and negative ideal solutions and alternatives are ranked according to their relative closeness. The ideal solution has the shortest distance from the positive ideal solution and the farthest distance from the negative ideal solution [197, 198]. Among these methods, TOPSIS offers a simple way of combining the preferences of multiple groups for group decision-making, which is the most relevant to this research. It is the most commonly used method in the sustainable supplier selection problem [199–201]. A multi-criteria intuitionistic fuzzy TOPSIS method is applied for the evaluation of supplier problems with multi decision-making groups [199, 200]. The study in [201] proposes an extended TOPSIS method and applies it in the sustainable supplier selection problem to deal with the multiple decision-making groups with different concerns. Besides, the TOPSIS method is adopted to solve the decision-making of a multi-objective regional energy system planning problem by taking a multi-actor perspective by Wang *et al.* [202]. Overall, the TOPSIS technique is an effective technique to deal with MCDM problems with multiple decision-making groups.

5.2.3. MCDM for social acceptance analysis

Social acceptance is always difficult to achieve and analyze, no matter in whichever system. Furthermore, decision-making with multiple criteria, multiple alternatives, and multiple decision-making groups is always a complex task to implement. Our literature review shows that the problem of social acceptance and MCDM in renewable energy projects has been studied extensively. However, the study of using MCDM to analyze to which extent the alternative is socially acceptable and thus to select the best solution has not often been addressed. Considering the objective of the study, MCDM is considered an effective tool to select a socially acceptable cost allocation approach. It enables a critical evaluation and analysis of the multiple alternatives considering the criteria defined, and finally identifies a socially acceptable cost allocation approach considering the preferences and interests of multiple decision-making groups involved in the energy systems. This approach can be applied in any local energy system that is focusing on the social acceptance of local stakeholders.

5.3. Conceptualization of social acceptance

Social acceptance covers many aspects and can be expressed in various forms, and it is not an easy task to conceptualize it. One related research is tariff design in large power systems. It is the interconnection between power systems and the end-users by allocating costs to them [47, 61]. Regulators make regulatory principles to regulate these activities in order to arrive at a proper tariff design [46, 75]. These principles are classified into three categories: system sustainability principles, economic efficiency principles, and consumer protection principles [45, 50]. Detailed information about these regulatory principles can refer to in the following studies: [45–47, 64, 66]. Even though cost allocation in ICESs is not the same as tariff design in large power systems, the concepts of these principles can be translated as the criteria to evaluate how well the costs are allocated. In the context of this research, the main research question is how to design cost allocation in ICESs in a socially acceptable manner. The study in this area is often missing in the literature, especially considering the effects of the procedure and the outcome of cost allocation. Therefore, in this study, social acceptance is conceptualized from the perspective of procedural and distributive justice by considering ensuring a fair procedure and a fair outcome. The two aspects contribute to the social acceptance of cost allocation. The factors that influence procedural and distributive justice are defined in detail by taking the principles in tariff design in large power systems for reference.

5.3.1. Procedural justice

Procedural justice is associated with equitable access and participation in the process of decision-making [171, 175]. In this section, the factors that may influence the acceptance of cost allocation in ICESs are identified and conceptualized from the following perspectives.

Transparency

All the relevant information should be transparent to local stakeholders and protect their privacy at the same time. Firstly, the objectives, procedures, principles, and the approach for allocating costs should be clear to all the stakeholders to ensure they understand and accept these mechanisms well. Secondly, costs and benefits, energy generation, energy exchange data, and other relevant data associated with the process of cost allocation should be transparent to stakeholders. Thirdly, the resulting consequences of cost allocation should be clear to them to make sure they accept the effects of the cost allocation results. Fourthly, they should be clear about how they are charged for their energy usage.

Participation

All the stakeholders are given the right to be able to fully participate in the process and the decision-making of cost allocation. The decision-making issues involved in cost allocation in ICESs include setting goals, making principles, and selecting approaches for allocating costs and other related activities. Full participation in the process of allocating costs helps stakeholders understand how the costs are allocated, and thus increases the acceptance of the cost allocation results and their consequences.

Accessibility

All the stakeholders have access to all the relevant information. The information should not be partially accessible to some stakeholders, while not accessible to others. Accessibility is used to ensure that all stakeholders are treated equally.

Non-discrimination

All the stakeholders should be treated equally without discrimination. Firstly, they are engaged in a non-discriminatory way and have equitable access, participation, and strategy-making in the process of cost allocation. Secondly, they should be given equal opportunity to express their preferences and opinions. Thirdly, their opinions and suggestions should be taken into consideration equally and treated with respect.

Consultation

Considering the different educational backgrounds and understanding levels of local stakeholders, consultation should be provided in the process to ensure they understand the problem. For instance, some local residents may not understand the cost allocation approach well enough that they may not dare to express their opinions or provide constructive suggestions. In this case, they can consultant any problem they have and should get professional answers. Furthermore, the consultation also contributes to active participation in the decision-making process, such as selecting an appropriate cost allocation approach.

5.3.2. Distributive justice

Distributive justice concerns with a fair distribution of the costs and benefits in ICESs. People may have different measuring standards for fairness, so it is not easy to define fairness directly. In this section, the essential factors influencing distributive justice are defined with an extensive illustration.

Vertical and horizontal equity

According to the study in [203], the concept of equity is mainly broken down into two aspects: vertical and horizontal equity to evaluate the equitable outcomes in tax policy. Vertical equity refers to that people who earn more should pay more tax, and horizontal equity means people who earn the same should pay the same tax. While coming back to the case of cost allocation, the energy bills of customers are affected by their consumption behavior. Therefore, we conceptualize vertical and horizontal equity from the perspective of energy consumption. Vertical equity is defined as customers who consume more energy at the same time should pay more, regardless of how the energy is utilized. Horizontal equity is defined as customers who consume the same amount of energy at the same time should pay the same. The underlying principle of the concept is that the method meets the requirement of distributive justice if the cost is allocated based on the energy price of €/kWh, and this price is the same for each consumer at that moment. It provides a way to evaluated distributive justice intuitively.

Cost causality

The basic concept of cost causality is the costs should be allocated to those who made it. A cost causality method should reflect the underlying energy bill structure of the energy system. In this chapter, the drivers that cause costs are used to define cost causality considering the characteristics of the load profile. The load profile is the basic element in the energy system, and it is the most influencing factor that affects costs. Energy (kWh) and peak demand (kW) are the key elements of the load profile. They are also considered as cost drivers because they reflect the relationship between costs and their causes [45, 61, 138]. Customer service costs are also part of the energy bill representing fixed costs in the cost structure. In this thesis, we use energy reflectivity, capacity reflectivity, and customer service reflectivity to represent the three cost drivers. They are the three elements in the assessment of cost causality structure, and they are independent of each other. The assessment approach helps to evaluate to which extent the method reflects cost causality by considering if the billing structure consists of these components.

Time or consumption level reflectiveness

Energy consumption has the characteristic of time-varying and repetitiveness over time for households. Peak demand is the main factor that making the energy system costs very high. Therefore, customers who consume more energy in peak hours should pay more. This could be achieved by providing dynamic charging information in the form of time difference or consumption level difference.

Time reflectiveness refers to that the energy price indicates time differences since the load profile is time-dependent. Consumption reflectiveness refers to that the energy price reflects the maximum capacity difference since peak demand is the influencing factor on costs and system operation. They are the economic signals sent to customers to help them adjust their consumption behavior, for example, shifting peak demand to off-peak hours or peak generation hours, limiting electricity consumption within a threshold at any time. This factor contributes to the efficient usage of the energy system.

Cost reflectiveness

Fairness is an essential issue no matter in whichever energy system, which is the same in the context of cost allocation in ICESs. The costs allocated to local community members should be fair enough to reflect the costs they cause for their energy consumption. Cost reflectiveness is conceptualized as to which extent it reflects the costs local community members should pay [62]. In this study, the costs of investing in DERs by themselves are defined as the cost they should pay since the energy consumption in ICESs is mainly from DERs. This cost is used to compare with the energy bill a customer pays in the ICES to evaluate whether or not the method is cost-reflective.

Cost predictability

The results of cost allocation should remain more or less the same in the short-term (for instance, in two consecutive years) and gradually change in the long-term (for instance, in the lifetime of the energy system) without significant changes in energy generation and consumption. Therefore, the results of cost allocation should be predictable, it is one of the main factors that contributes to the long-term commitment of local community members to stay in ICESs and sustainable and stable development of ICESs. In this study, cost predictability is used to indicate the changes in energy bills [62]. Local community members can evaluate if the selected method is cost predictable by comparing the energy costs in the two consecutive years. If the change is small or near zero, it indicates that the method can provide stable cost allocation results without sudden changes in energy bills in the following years.

5.3.3. Summary

The framework of social acceptance is summarized in Figure 5.1. The framework provides a comprehensive overview of the factors that affect the social acceptance of the involved stakeholders. Procedural justice should be well-followed to ensure the process of allocating costs are acceptable by the local community members and their benefits and rights are well-protected. This should be well-executed by the manager of the community energy system. The criteria affecting distributive justice are possible to be quantified. They have the characteristics of objectivity, which are influenced by the performance of cost allocation methods.

Procedural justice ensures a fair process of allocating costs and increases the acceptance of cost allocation results. A fair procedure is more likely to lead to a fair cost allocation result, and consequently, local community members will show more commitment towards the cost allocation mechanism in ICESs and their long-term relationship with the community. Distributive justice focuses on the outcome of cost allocation, it ensures a fair allocation of costs. A fair outcome is important for cost allocation in ICESs because it maintains the community's well-being. The results are determined by the selected cost allocation method. ICESs are an energy system without regulators that the cost allocation activity is not regulated or guided by the local institution. Therefore, the criteria affecting procedural and distributive justice should be considered the principles to ensure the costs are allocated in a socially acceptable manner. Furthermore, it is essential to take the preferences of local stakeholders into account on these factors when selecting the cost allocation method. The criteria defined above can be used to assess the performance of cost allocation methods and select the one that satisfies the preference of local community members, which will be introduced in the following sections. Overall, procedural and distributive justice are indispensable to ensure a socially acceptable cost allocation

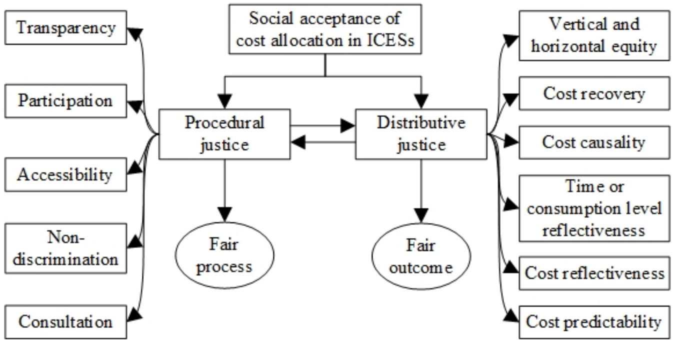

Figure 5.1: The framework of social acceptance

in ICESs. They are the essential elements to help determine a good cost allocation outcome for the whole community.

5.4. Social acceptance analysis of cost allocation methods

According to the criteria defined in Section 5.3.2 affecting the social acceptance of the results of cost allocation in ICESs, the performance of each method is evaluated in terms of distributive justice. The first three criteria (equity, cost causality, and time or consumption level reflectiveness) are evaluated by the energy bill structure of the cost allocation method. If the energy bill structure includes the criteria as a pricing component, the method satisfies that criterion, otherwise, it does not. For the last two criteria (cost reflectiveness and cost predictability), their values are calculated in chapter 4 for each individual customer according to their definition.However, in order to estimate the overall performance of each method, the variance of a set of cost reflectiveness and predictability from individual customers is used. According to their definitions, a value close to zero shows the best performance. Therefore, the value of zero is taken to be the average value in the calculation of variance to see how much the results deviate from the best performance. The variance of cost reflectiveness (or predictability) is calculated by the following equation:

$$var_{ref/pre_j} = \sqrt{\frac{\sum_{i=1}^{Q} ref/pre_{i,j}{}^2}{Q-1}} \tag{5.1}$$

where var_{ref/pre_j} is the variance of cost reflectiveness (or predictability) of method j, $ref/pre_{i,j}$ is the index for cost reflectiveness (or predictability) of method j for user i, Q is the number of users.

The performance of each cost allocation method in terms of the five criteria analyzed above is summarized in Table 5.1.

Table 5.1: Performance assessment of cost allocation methods

Cost allocation methods	Vertical and horizontal equity	Cost causality			Time or consumption level reflectiveness	Cost reflectiveness	Cost predictability
		Energy reflectivity	Capacity reflectivity	Customer service reflectivity			
M1: Cost allocation based on the number of users	0	0	0	0	0	0.30	0.00
M2: Flat energy pricing	1	1	0	0	0	0.29	0.18
M3: Time-of-use energy pricing	1	1	0	0	1	0.20	0.18
M4: Capacity subscription	0	0	1	0	0	0.20	0.18
M5: Coincident peak pricing	0	0	1	0	0	0.20	3.84
M6: Non-coincident peak pricing	0	0	1	0	0	0.73	0.47
M7: Segmented energy pricing	1	1	0	0	1	0.37	0.24
M8: Average and excess method	0	0	1	0	0	0.28	0.28
M9: Two-part pricing	1	1	1	0	0	0.27	0.25
M10: Multi-part pricing	1	1	1	1	0	0.26	0.19

1 stands for the method satisfies the criterion; 0 stands for the method does not satisfy the criterion

5.5. Multi-group and multi-criteria decision-making (TOPSIS)

In this section, the MCDM method is applied to support the selection of the cost allocation method due to the participation of many local community members with various preferences and many alternatives in the decision-making process.

5.5.1. Multiple decision-making groups

The objective of using MCDM is to help local community members select a socially acceptable cost allocation method. Therefore, it is essential to take local opinions and preferences into account. Local community members vary from each other in education background, financial conditions, employment situations, social concerns, and energy demand level [157, 204]. They may hold different points of view towards cost allocation based on their situation. Local community members are categorized into several decision-making groups according to their preferences. Members with the same or similar preferences are attributed to the same group. For some decision-making groups, some criteria are more important than others, and they may focus on one or more aspects of the criteria. Therefore, major preferences are considered for each decision-making group in order to simplify the classification.

According to the five criteria defined in Section 5.3.2, the first three criteria (equity, cost causality, and time or consumption level reflectiveness) determine if the costs are allocated in a fair manner irrespective of the results. They are considered together the major preferences for local community members who concern about fair manner. Cost reflectiveness indicates how well the costs are allocated, which is focusing on a fair result. Cost predictability indicates how stable the cost allocation result is in the long-term, which is focusing on stability. Cost reflectiveness and predictability present cost-related issues, but from different dimensions. Local community members may care about one or any combination of these issues, therefore,

Table 5.2: The major preferences of the seven decision-making groups

Group number	Group name	Criteria				
		Equity	Cost causality	Time/ consumption reflectiveness	Cost reflectiveness	Cost predictability
1	Fairness-focus	√	√	√		
2	Cost reflectiveness-focus				√	
3	Cost stability-focus					√
4	Fairness & cost reflectiveness-focus	√	√	√	√	
5	Fairness & cost stability-focus	√	√	√		√
6	Cost reflectiveness & stability-focus				√	√
7	Perfect-focus	√	√	√	√	√

there exist many decision-making groups. Based on this, the local community members are categorized into seven groups according to their major preferences. The major preferences of the seven decision-making groups are summarized in Table 5.2. It should be noted that if more criteria and decision-making groups are added, the formulation of the objectives will need to be changed correspondingly, but our proposed methodology is still valid. The seven decision-making groups and their major preferences are now discussed further.

The fairness-focus (Group 1) decision-making group members are aligned in their preferences that they care about if the costs are allocated in a fair manner irrespective of the actual costs assigned to them. The cost reflectiveness-focus group (Group 2) consists of the members who care about the results of cost allocation instead of the allocation process, as long as the final costs reflect the real costs they made for the energy consumption. The cost stability group (Group 3) presents the members who care about the changes in costs in the following years. They do not expect a sudden change in their energy bills provided that their energy demand does not change a lot in the following years. For the following decision-making groups (Group 4, 5, 6, and 7), it is the combination of the single concerns. The classification of the decision-making groups makes it simple for local community members to express their opinions in practice.

5.5.2. TOPSIS for multi-group decision-making

The ten cost allocation methods will be assessed based on the major preferences of local community members by using the TOPSIS method. Many steps are involved in the MCDM problem. In this section, the process for multi-criteria decision-making in the context of cost allocation in ICESs is elaborated step by step to further facilitate the selection of a socially acceptable method.

Step 1 is to construct the decision-making matrix considering the values ($v_{m,n}$) of each criteria m, $\forall m \in M$ for each alternative n,$\forall n \in N$.

Step 2 is to normalize the values of the criteria. Criteria are selected from different aspects and measured on different scales for cost allocation in ICESs. It is necessary to transform them to a common scale to ensure comparability and ranking of alternatives in decision-making [205, 206]. Normalization is the process of mapping the values of all criteria, which are measured on different scales, to a common scale and comparable units in the interval [0, 1] [207]. It enables the comparison of all criteria measured with different units, and thus to evaluate the performance of each alternative. For the criterion of vertical and horizontal equity and time or consumption level reflectiveness, the values are 0 and 1, they are already normalized. Three aspects are included in the criterion of cost causality. The sum of the values of the three aspects is the total value of cost causality. A linear max-min normalization method is used to map these values to the interval [0, 1] [208]:

$$NV_{cau,n} = \frac{v_{cau,n} - v_{cau,n,min}}{v_{cau,n,max} - v_{cau,n,min}} \tag{5.2}$$

where $NV_{cau,n}$ is the normalization value of cost causality for method n. $v_{cau,n}$ is the value of cost causality for method n. $v_{cau,n,min}$ and $v_{cau,n,max}$ are the minimal and maximal value of cost causality for method n.

For the criteria of cost reflectiveness and predictability, a variance value is used, therefore, the smaller the value is, the better the performance of the criteria. A linear min-max normalization method is also used to map these values into the interval [0, 1] [208]:

$$NV_{ref/pre,n} = \frac{v_{ref/pre,n,max} - v_{ref/pre,n}}{v_{ref/pre,n,max} - v_{ref/pre,n,min}} \tag{5.3}$$

where $NV_{ref/pre,n}$ is the normalization value of cost reflectiveness (or predictability) for method n. $v_{ref/pre,n}$ is the variance value of cost reflectiveness (or predictability) for method n. $v_{ref/pre,n,max}$ and $v_{ref/pre,n,min}$ are the maximal and minimal value of cost reflectiveness (or predictability) for method n. Thus, a normalization matrix ($NV_{m,n}$) contains the normalized value of each criteria for each cost allocation method is obtained.

Step 3 is to define the weighted normalized decision matrix ($R^a_{m,n}$) for each decision-making group a, $\forall a \in A$, where A is the set of the seven decision-making groups. If the criterion is the major preference for the decision-making group, the weight is assigned to be 1, otherwise 0. It is assumed that the weights of all the decision-making groups are the same (as the value of 1), because the focus of this work is only to show the proposed framework to select a socially acceptable cost allocation by using the TOPSIS method.

$$R^a_{m,n} = w^a_m NV_{m,n} \quad \forall a \in A, \forall m \in M, \forall n \in N \tag{5.4}$$

where w^a_m is the weight for criteria m for decision-making group a.

Step 4 is to find the best point (P^{a+}_m) and the worst point (P^{a-}_m) regarding each criterion m for each decision-making group a.

$$P_m^{a+} = \max_{\forall n \in N} R_{m,n}^a \quad \forall m \in M, \forall a \in A \tag{5.5}$$

$$P_m^{a-} = \min_{\forall n \in N} R_{m,n}^a \quad \forall m \in M, \forall a \in A \tag{5.6}$$

Step 5 is to derive the positive distance S_n^{a+} and the negative distance S_n^{a-} for each alternative n for each decision-making group a. The distances are computed by using the Euclidean distance between each alternative and the best or the worst point. A small positive distance and a large negative distance indicate a good solution.

$$S_n^{a+} = (\sum_{\forall m \in M} P_m^{a+} - R_{m,n}^a)^{\frac{1}{2}} \tag{5.7}$$

$$S_n^{a-} = (\sum_{\forall m \in M} P_m^{a-} - R_{m,n}^a)^{\frac{1}{2}} \tag{5.8}$$

Step 6 is to calculate the normalized coefficient of closeness (CC) (CC_n^a) for each alternative n for each decision-making group a. Firstly, the absolute value of CC for each solution n for each decision-making group a is calculated:

$$ACC_n^a = \frac{S_n^{a-}}{S_n^{a+} + S_n^{a-}} \tag{5.9}$$

Then, ACC_n^a is normalized to CC_n^a, which represents the degree of optimality of alternative n for decision-making group a. A CC score of 1 means that the solution is the closest to the best alternative, and the furthest to the worst alternative for decision-making group a.

$$CC_n^a = \frac{ACC_n^a - ACC_{min}^a}{ACC_{max}^a - ACC_{min}^a} \quad \forall n \in N, \forall a \in A \tag{5.10}$$

Step 7 is the final step to combine the preferences of all the decision-making groups, in order to further reach a consistent solution. A geometric mean of the CC scores for all the decision-making groups is calculated to define an average value of CC score ($CC_n^{geo,\ ave}$) [196]. In the following equation, A is the size of the decision-making groups. The larger the average value is, the better the performance of the alternative.

$$CC_n^{geo,\ ave} = (\prod_{\forall a \in A} CC_n^a)^{\frac{1}{A}} \quad \forall n \in N \tag{5.11}$$

In order to further analyze the results, two more values: maximin and minimax, which are defined by [202] are used. The maximin value indicates that the alternative achieves the highest least satisfaction for the decision-making groups, and the minimax value indicates a risk-neutral solution for the decision-making groups. They are calculated by the following equations:

$$maximin = \max_{\forall n \in N} (\min_{\forall a \in A} CC_n^a) \tag{5.12}$$

$$minimax = \min_{\forall n \in N} (\max_{\forall a \in A} CC_n^a) \tag{5.13}$$

5.6. Multi-group and multi-criteria decision-making: results analysis

The value of each cost allocation method towards each criterion is obtained based on their performance assessment, and they have then been processed with the MCDM technique (TOPSIS). In this section, the results will be presented. Firstly, the value of each criterion after normalization is calculated based on the equations in Step 2 and is summarized in Table 5.3. The CC scores for each decision-making group in terms of the ten alternatives are obtained, as shown in Fig 5.2. A score of 1 indicates that the alternative is the most desirable and a value of 0 zero indicates the most undesirable for the specific decision-making group based on the overall evaluation of these major preferences among all the alternatives. The main observation is that groups 1, 4, 5, 6 and 7 are well aligned with the best alternative (M3), while the other two groups often have diverging preferences with them. The best alternatives for group 2 are methods 2 and 4. And the best alternative for group 3 is method 1. It is noted that for groups 1, 2, 5 and 6, they have multiple alternatives with the same and the highest CC scores. It indicates that all these alternatives show a better performance in terms of their major preferences. In addition, the best alternatives for groups 2 and 3 are not a good alternative for the other decision-making groups. This is because their major preference is focusing on cost issues instead of fairness issues. The best solution for Group 3 (M1) turns out to be a bad solution for other groups. This is because the major preference for the stable-focus group is the stable change in energy bills regardless of costs and fairness issues. Furthermore, method 3 seems to be the most acceptable solution for all decision-making groups, since the least satisfied group still has a score of 0.96.

Table 5.3: The value of each criterion after normalization

Cost allocation methods	Vertical and horizontal equity	Cost causality	Time or consumption level reflectiveness	Cost reflectiveness	Cost predictability
M1: Cost allocation based on the number of users	0.00	0.00	0.00	0.83	1.00
M2: Flat energy pricing	1.00	0.33	0.00	1.00	0.96
M3: Time-of-use energy pricing	1.00	0.33	1.00	1.00	0.96
M4: Capacity subscription	0.00	0.33	0.00	1.00	0.96
M5: Coincident peak pricing	0.00	0.33	0.00	0.00	0.00
M6: Non-coincident peak pricing	0.00	0.33	0.00	0.68	0.88
M7: Segmented energy pricing	1.00	0.33	1.00	0.85	0.94
M8: Average and excess method	0.00	0.33	0.00	0.86	0.93
M9: Two-part pricing	1.00	0.67	0.00	0.89	0.94
M10: Multi-part pricing	1.00	1.00	0.00	0.94	0.95

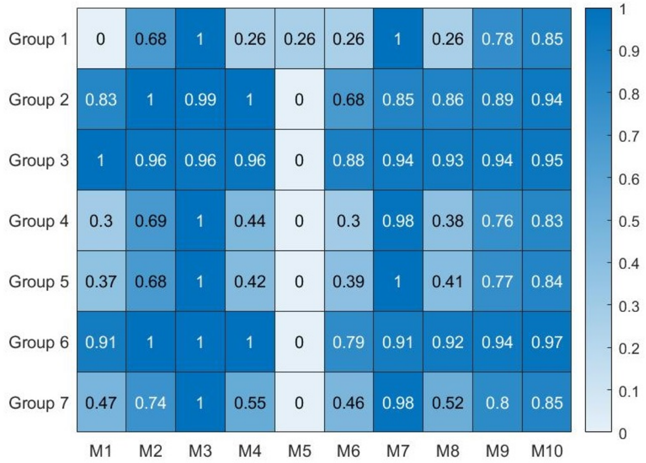

Figure 5.2: The CC score of each decision-making group in terms of the ten alternatives

In practice, only one cost allocation method is required to allocate costs in ICESs, therefore. Besides the best solutions for each decision-making group, it is essential to arrive at an alternative that considers all the groups involved in the local community. In this study, the single solution is quantified using the geometric average solution, maximin solution, and minimax solution. It shows the solution combining all the major preferences of the decision-making groups. The average CC score for each alternative considering all the decision-making groups in terms of the three solutions is shown in Fig 5.3. It is noted that for the first two methods, the highest average CC score is the best alternative and the lowest score is the best alternative for the last method (minimax solution), as shown in the red circle.

The geometric average solution is calculated based on Eq. 5.11. Method 3 has the highest average CC score among the ten alternatives. It is the most desirable cost allocation method combining all the major preferences of the seven decision-making groups. And method 7 is comparable with this solution.

The maximin solution is calculated based on Eq. 5.12. It may not be the best but is acceptable for every local community member in ICESs. The maximin solution is calculated by taking the minimal CC score of the seven decision-making groups first, and then taking the highest minimal CC score. Therefore, it has the highest least satisfaction for the decision-making group. Compared to the average solution, method 3 has the highest maximin score. It corresponds to the results presented in Fig. 5.2 that method 3 is the most desirable solution for the seven decision-making groups.

The minimax solution is calculated based on Eq. 5.13. It also considers the least regret solution that all the decision-making groups will have the least regret after decision-making. Method 5 turns out to be the least regretful solution. This solution only shows the feature that follows the criterion of cost causality in terms

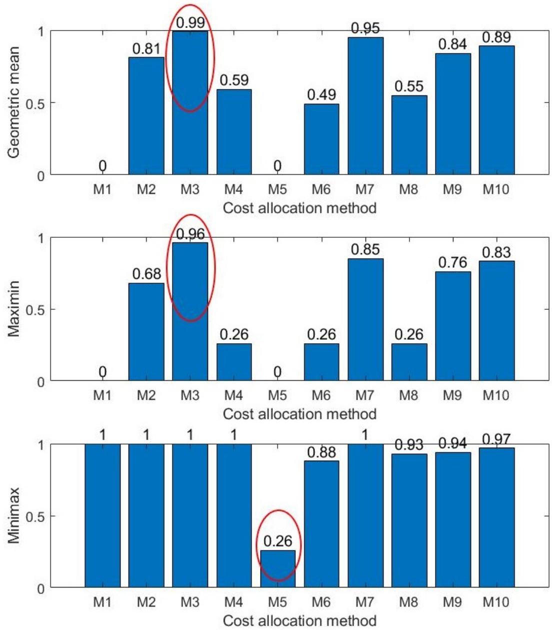

Figure 5.3: The average CC scores for each alternative considering all the decision-making groups for the three solutions

of capacity reflectivity. Considering the CC score of each decision-making group shown in Fig. 5.2, it is the last best solution for the other decision-making groups except group 1. Even though it is the least regretful solution, it may not a good solution for all the decision-making groups.

In practice, the composition of the community may be different, there may be more or fewer decision-making groups in the community. In this case study, we take groups 1 and 6 as the two decision-making groups in the community. Group 1 cares about if the costs are allocated in a fair manner, and group 6 cares about the results of cost allocation, as long as the results reflect the cost they should pay in actuality and the energy bills are stable in the long-term. The average solution for the two decision-making groups is shown in Figure 5.4. The results show that method 3 is the best solution combining the major preferences for the two decision-making groups. Our approach works with different decision-making groups. Once the decision-making groups are determined, it is easy to apply the approach proposed in this chapter to support the local community members in selecting a cost allocation satisfying their requirements.

In this study, it is assumed that the number of local community members (weight of each decision-making group) in each group is equal. This assumption is made because the main objective of this work is to show the adoption of the MCDM tool to solve the decision-making problem. However, the changes in the weights of

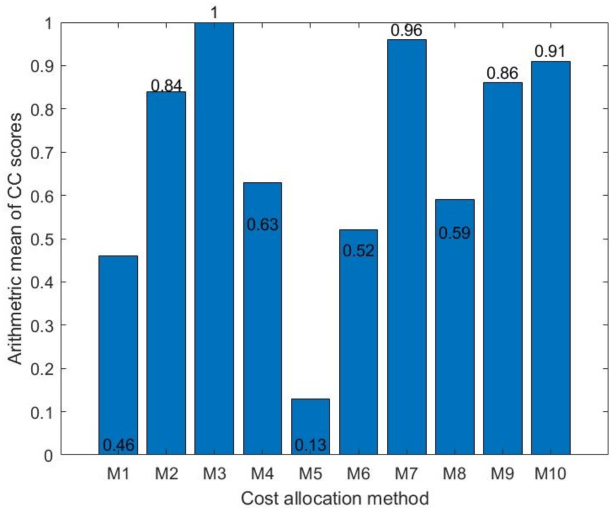

Figure 5.4: The average solution for the decision-making groups 1 and 6

Table 5.4: Scenarios with different percentages of local community members in each group

Scenarios	S1 (%)	S2 (%)	S3 (%)	S4 (%)	S5(%)
Group 1	10	30	50	70	90
Group 6	90	70	50	30	10

the decision-making groups may have effects on the final results. In order to see how this would influence the results, an analysis with different percentages of local community members in decision-making groups 1 and 6 is introduced, as shown in Table 5.4. The percentages are translated to the weights of the two decision-making groups. The geometric mean cannot be used because it multiplies all the values together. Instead, the arithmetic mean is used to calculate the average score for all the decision-making groups. The average solution for the five scenarios is shown in Figure 5.5. The results show that the best solution for the whole community is influenced by the percentage of local community members in the decision-making group. The best solution is method 3 for the five scenarios considered in the research. However, it should be noted that the average score of methods 5 and 7 increases with the increase in the percentage of group 1, and method 7 tends to be the best solution when group 1 takes the majority (90% in this case). And when group 6 takes the majority (which is also 90%), method 2 tends to be the second-best alternative. The analysis done here indicates that MCDM is an effective tool to help local community members select a method that is socially acceptable to them.

This section shows the results of the MCDM problem of selecting a socially acceptable cost allocation method by using the TOPSIS method. The performance of cost allocation methods is assessed based on their characteristics. The local commu-

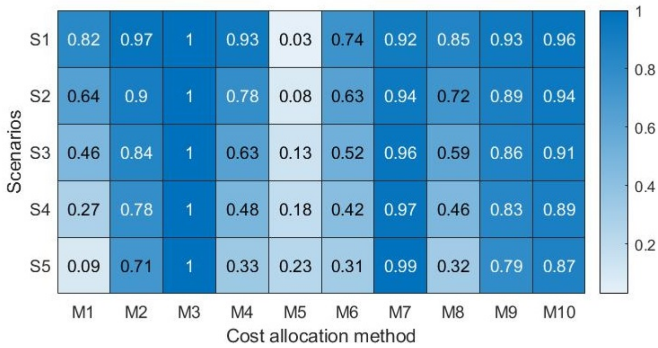

Figure 5.5: The analysis for different weights assigned to the decision-making groups

nity is categorized into different decision-making groups considering the differences in their major preferences. Seven decision-making groups are considered in this study, and their major preferences vary from fairness, cost reflectiveness to stability and any combination of them. The numerical results show that method 3 is the best solution for the seven decision-making groups considered in this research. And method 7 is the second-best alternative yet acceptable for local community members. They cover relatively more comprehensive aspects of the five criteria compared to the other methods. In addition, the analysis of the weight of different decision-making groups indicates that the number of local community members in different decision-making groups influences the selection of best solutions. The approach proposed in this chapter can effectively deal with the changes in the number and the weights of decision-making groups, thus, provides a reliable solution to the local community.

5.7. Discussions and policy implications

5.7.1. Discussions

In the field of cost allocation in local community energy systems, the research on cost allocation is often missing. In addition, the engagement of local community members is an essential element in local community energy systems. Their involvement is the key factor that affects the success of the implementation of local community energy systems. The costs should be allocated in a socially acceptable manner in any local community energy system without regulation. However, the research on social acceptance is often addressed in the area of renewable energy technologies [158–160, 167, 168] . In this the, a social acceptance framework is designed from the perspective of procedural and distributive justice to ensure a relatively fair process and result. A fair process increases the acceptance of the results of cost allocation. Procedural justice and distributive justice interact with each other, they are the essential criteria that are required to follow to ensure that the costs are allocated in a socially acceptable manner. In this chapter, ten methods are adopted as the alternatives to allocate costs in ICESs, they are assessed in terms of the five criteria: equity, cost causality, time or consumption level reflectiveness, cost reflectiveness, and cost predictability.

Allocating costs in ICESs in a socially acceptable manner is a complex and difficult issue, where local community members need to reach an agreement on a cost allocation method. They have different preferences and interests, sometimes conflict with each other, which are the major reason that affects the success of cost allocation. It is also difficult to specify the preferences of each local community member, therefore, it is essential to classify them into several decision-making groups to simplify the process of collecting opinions from local community members. Therefore, it stands for a multi-group, multi-criteria, and multi-alternative decision-making problem. Seven decision-making groups are classified in this study according to the major preferences of local community members. The problem is solved by adopting MCDM (TOPSIS) method to help the local community members to select a socially acceptable cost allocation method. Three solutions (geometric mean, maximin, and minimax) are obtained combing all the major preferences of the seven decision-making groups. The results show that TOPSIS is an effective tool to solve the social acceptance problem in cost allocation in ICESs. The advantages of applying the MCDM method lie in that: (1) it simplifies the process of collecting opinions from local community members by considering decision-making groups, the only thing the local community members should do is to select the decision-making group (2) it is able to consider the preferences of all the decision-making groups in the selection of cost allocation method simultaneously (3) social acceptance is achieved by a quantitative measurable manner (4) the approach is still valid when more decision-making groups are added. It makes it easy for local community members to select a socially acceptable cost allocation method by using the proposed approach, which is also convenient for local managers to arrange these issues when allocating costs in ICESs. The obtained results can be used by any local stakeholders in local community energy systems in the decision-making process to select a method, which can lead to a relatively fair cost allocation result, and thus socially acceptable to them. The MCDM analysis selects a cost allocation method that follows the criteria that affect distributive justice, which further affects the social acceptance of the results of cost allocation. However, procedural justice is also an essential factor that cannot be neglected in practice to ensure a fair process.

5.7.2. Policy implications

ICESs are social-technical systems with physical and social network relationships. These systems are complex in the sense that they require decision-making from multi-institutional levels. A successful cost allocation in ICESs requires support from local authorities, local government, policymakers, regulators, system operators, and other related parties. Besides, a local community energy market committee should be established, which may consist of several experts in the energy market to regulate the cost allocation activities.

For local authorities or government, the approach proposed in this thesis provides them with promising policy-relevant results, which can be considered the instruments to manage the local community energy market to ensure both the process and the results of cost allocation are socially acceptable to local community members. Policymakers and local regulators should make appropriate policies and regulations to regulate cost allocation activities in local energy systems. Besides, they should send proper incentives and design supportive schemes to support local community energy markets. They should acknowledge the value the local community members can bring to the energy systems and the environment. Overall, tailored regulations should be made specifically for the context of local community energy markets, to provide them with sufficient autonomy to take full control of their energy systems. The support from local authorities can better contribute to the participation of local community members in the energy transition.

Considering the current situation, it is not realistic to have a 100% renewable energy system achieve self-sufficiency, the local community energy systems still require support from system operators. They are required to distribute energy and maintain local energy systems with a safe, reliable, and affordable grid. Besides, ICESs should be given certain policy support to have access to fair energy trading with the grid, such as reasonable feed-in tariff and export tariff to ensure their benefits.

For local community members, the approach provides them with the opportunity to fully participate in the process of cost allocation. And this also provides them with a sense of community belonging. The involvement of local community members, on one hand, increases the complexity of the cost allocation process, because a lot of local opinions and preferences are required to be taken into account. The cost allocation mechanisms, methods, and affecting factors should be well-explained to local community members by following procedural justice. The designed framework of social acceptance in this study can support this well. At the same time. It also requires the local community managers to map these preferences properly and carefully into the problem. However, on the other hand, once these issues are settled down, they are more willing to accept the results because the costs are already allocated in a socially acceptable manner to satisfy their overall requirements. Considering this point, it is beneficial for local managers or coordinators to manage the local community energy markets. Besides, a proper institution design should be promised since a collective decision has to be made to meet the individual requirements.

Regarding the cost allocation methods, ten possible alternatives are adopted in this research, in the future, with the mature of the local community energy market, regulators should develop more methods and provide more options for local community members to choose from. Besides, the social acceptance framework proposed in this study provides the local community energy market with strong regulation guidance to regulate the activity of cost allocation. To some extent, they can be considered the principles to follow when allocating costs in local energy systems. The MCDM method adopted in this research can be added to the policy package as one option to achieve socially acceptable cost allocation in the local community energy market.

5.8. Conclusions

The costs should be allocated in a socially acceptable manner in any local community energy system without regulation. The study in this chapter presents a systematic framework for the analysis of social acceptance of cost allocation in ICESs. Social acceptance is mainly affected by two aspects: procedural justice and distributive justice. Procedural justice ensures a fair process, and distributive justice ensures a fair result. Both aspects interact with each other and are indispensable in order to achieve the goal of allocating costs in a socially acceptable manner. The MCDM technique (TOPSIS) adopted in this chapter is a good representative tool to help local community members to select a socially acceptable cost allocation method. The framework can be used by local stakeholders in local community energy systems in the decision-making process to select a socially acceptable method. The social acceptance analysis done in this study contributes to the development of local community energy systems from a socio-economic perspective. Furthermore, this approach is achieved via a quantitative manner, considering the situation that it is not easy to obtain the preferences and opinions from local community members, as there are few pilot projects of ICESs currently. The approach is generic, indicating that other than the example considered in this thesis, the MCDM approach for the selection of cost allocation method is able to apply in different communities considering their preferences with minor adjustments on a case-by-case basis.

6

Extensive discussions

Mathematics is a place where you can do things which you can't do in the real world.

Marcus du Sautoy

6.1. Introduction

This thesis provides a systematic and integrated methodology to allocate costs in ICESs in a socially acceptable manner. However, besides this, ICESs still confront with many problems in the implementation of cost allocation in ICESs. In this chapter, we provide an overview of the main barriers and enablers for cost allocation in ICESs. Each issue is elaborated in detail with an extensive discussion on their possible effects on cost allocation and possible solutions.

This chapter is a slightly modified version of the paper "Cost allocation in integrated community energy systems - A review" published in the journal of Renewable and Sustainable Energy Reviews [55].

6.2. 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 [145, 146]. 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 [145]. Bilateral contracts are made between two parties to exchange energy at an agreed price [209], 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.

6.3. 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.

6.4. 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 on the gird of ICESs and energy exchange price should be taken into account in the selection of cost allocation methods for grid-connected ICESs.

6.5. 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.

6.6. 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.

6.7. Community management team

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 management team. 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.

6.8. Evaluation of the implementation

The focus of this thesis is to identify cost allocation methods, access their performance, and social acceptance analysis of cost allocation. However, the selected method may not work when conditions change, for instance, when new members join and new investment decisions are being made or existing members leave. It, therefore, is necessary to have an evaluation of the effectiveness of the adopted cost allocation method, such as an annual evaluation, to make sure that the whole community is always satisfied with the cost allocation. The process is essential for the sustainable development of an ICES in the long-term, and thus local community members can show more commitment to the community energy system. In addition, the evaluation process provides the local community with the opportunity to participate in the demand response activity. They can adjust their consumption behaviors to save energy bills in the following years by selecting an effective cost allocation method. This kind of evaluation process makes both the community energy system and the cost allocation to be flexible and acceptable to local community members.

6.9. Conclusions

The success of cost allocation in an ICES is influenced by many barriers and factors. In this chapter, we illustrated several essential barriers, provided possible solutions, and discussed their possible effects. These practical solutions pave the way for future implementation of cost allocation in ICESs. Based on this, the community management team can make proper mechanisms beforehand to prevent the occurrence of these problems. In addition, they can take more effective measures to tackle the problems that might meet in the process.

7

Conclusions

Don't let the noise of others' opinions drown out your own inner voice.

Steve Jobs

This final chapter summarizes the work and results described in this thesis by providing the answers to the main research question and each sub-question, as well as the main research contributions. Finally, recommendations for future research direction are given with suggestions.

7.1. Conclusions

The objective of this thesis is to allocate costs in an ICES in a socially acceptable manner. A systematic framework is proposed in order to ensure a successful cost allocation in ICESs, which include the objectives, procedures and methods. Among them, the selection of a socially acceptable cost allocation method is much more complicated, a diagram is presented in Figure 7.1 in order to understand the workflow and the knowledge provided in each chapter. It also shows how the approach can be applied in a community energy system in practice. The required input from local community members is their selection of the decision-making groups. The other required components are provided in different chapters. Finally, a socially acceptable cost allocation method is selected for the community. In addition, the whole process follows with the procedural justice to ensure local community members are fully involved in the decision-making. Overall, the research done in this thesis provides necessary approaches and tools to ensure a socially acceptable cost allocation design in an ICES. The logic of the cost allocation design in this thesis is as follows: (1) the community manager first calculates the costs that are required to be recovered (2) the community manager collect local community members' opinions upon the decision-making groups as the input of the framework shown in Figure 7.1 to select a cost allocation method that is socially acceptable to the whole community (3) the final step is to allocate costs to local community members according to the method selected in step 2.

7.2. Answers to research questions

In line with the objective of this thesis, the main research question addressed in this thesis is:

How to design cost allocation in an ICES in a socially acceptable manner?

Specifically, the main research question is decomposed into four sub-questions. In the following part, the main findings towards each sub-question are summarized.

Sub-question 1: What can be learned from electricity tariff design with respect to cost allocation design in an ICES?

Sub-question 1 is posed to review tariff design issues in large power systems and investigate their applicability to cost allocation in ICESs. This sub-question is answered in Chapter 2, by conducting a literature review of tariff design, which includes objectives, regulatory procedures, tariff structure design, regulatory principles, and most widely used cost allocation methods. By doing this, we investigate

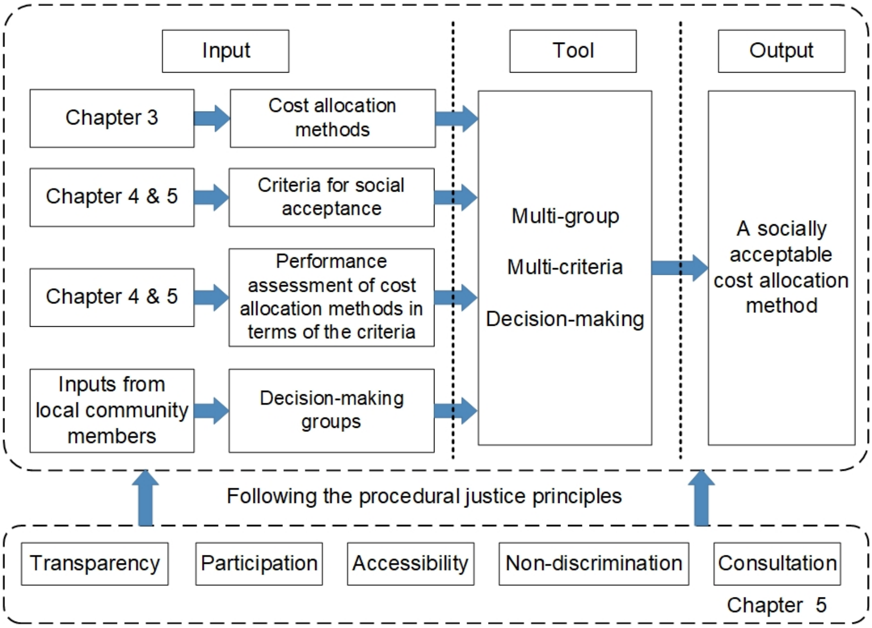

Figure 7.1: A diagram for answering the main research question

how to translate the concept of tariff design into cost allocation in ICESs. Furthermore, we discussed the experience learned and possible modifications to the application of cost allocation methods to cost allocation in ICESs. The discussion also includes a comprehensive analysis of the potential problems that have impacts on cost allocation in ICESs and possible solutions. According to the analysis, a systematic framework can be formulated learning from the framework adopted in tariff design, and these methods are also potential options for allocating costs in ICESs. This review chapter paves the way for the application of fair cost allocation in ICESs by providing a systemic framework.

Sub-question 2: What is the framework for cost allocation design and which approaches can be adopted for cost allocation in an ICES?

The objective of this sub-question is to develop a framework and methods for cost allocation design in an ICES. Based on the lessons we learned from tariff design, we developed a systematic framework for cost allocation design, specifically including the objectives, procedures, required components, and various options for cost allocation methods. These keys are essential elements for ensuring a successful implementation of cost allocation in an ICES. The framework designed here can be applied to any community energy system with a similar characteristic to ICESs. In the framework, social acceptance analysis is considered, which is not covered in large power systems. Therefore, the main objective is to allocate costs in a socially acceptable manner by taking the local communities' opinions and preferences into account. One more step is added in the procedure: to select a socially acceptable cost allocation method by the decision-making from local community members. Furthermore, the cost allocation methods are explained in detail to show how their concepts are translated from tariff design, and how they are derived from underlying principles. The methods are also formulated mathematically to show how they are implemented and what data are required. These explanations and mathematical formulations make sure that these methods can be applied to a local community energy system directly to allocated costs to community members. This sub-question is answered in Chapter 3. Overall, the framework and approaches proposed in this chapter are guidelines for a local community manager and members to follow, to ensure that costs are allocated in a proper manner.

Sub-question 3: How to assess the performance of the cost allocation methods?

Cost allocation methods perform differently with respect to various criteria due to their different characteristics. There is also no consensus on which method is the best. It is, therefore, necessary to assess their performance and to show their differences. In any energy system, costs should be allocated to those who cause them, and benefits to those who make the investments, in order to promote fairness. A cost-reflective tariff reflects the contribution of consumers to the energy system and incentivizes them to utilize energy in a cost-efficient manner. A cost-predictable tariff helps consumers estimate the energy bills they have to pay. Thus they have the incentive to take action to adjust their consumption behaviors. Cost reflectiveness and predictability are proposed and defined as the criteria to assess the performance of the various cost allocation methods. Cost reflectiveness is used to gain insights into how well the costs are allocated, and cost predictability is adopted to see how the energy costs change in the long-term.

This sub-question is answered in Chapter 4, by conducting a case study to evaluate the performance of the ten cost allocation methods presented in Chapter 3 in terms of cost reflectiveness and predictability. From the analysis of the results, we conclude that methods with energy as their single charging component perform better than either those with capacity as their sole component or those allocating costs based on the number of users in terms of cost reflectiveness and predictability. Our assessment should facilitate local community members in selecting a method that satisfies their requirements.

Sub-question 4: How to select a socially acceptable cost allocation method?

ICESs focus on the engagement of local community members, they can participate in the decision-making process, on such matters as making investments in community DERs and selecting a cost allocation method, so that they take full control of the energy system. Costs should be allocated in a socially acceptable manner since there is no regulation in ICESs. Both the process and the results should be socially acceptable by the local community members. A fair process increases the understanding and the acceptance of the cost allocation outcomes, and a fair outcome is important for the community's acceptance of cost allocation. According to the assessment in Chapter 4, cost allocation methods perform differently due to their characteristics. Local community members may hold different points of view towards the methods. It is expected that it can satisfy the requirements of stakeholders to the best when selecting a cost allocation method. In addition, local community members can be classified into several decision-making groups according to their major preferences. It, therefore, stands for a multi-group, multi-criteria and decision-making problem. Methods that can handle all these criteria are multi-criteria decision-making, which can take the preferences of all the stakeholders into account and further assist their decision-making (select cost allocation method).

This sub-question is answered in Chapter 5, by adopting a multi-group multi-criteria decision-making approach to evaluate social acceptance, in order to further to select a cost allocation method socially acceptable to local community members. The results show that our approach is unique and useful when multiple decision-making groups have to decide together upon the cost allocation method. It is able to provide quantitative results and optimal decisions from a multi-group decision-making perspective. The methodology developed in this thesis can be applied to any local community energy system, and the obtained results can be used by decision-makers to help them in the decision-making process.

7.3. Research contributions

The contributions of this thesis are as follows:

- *Cost allocation framework in ICESs.* This thesis provides a systematic framework for ensuring a successful cost allocation in ICESs, including objectives, procedures, and required components. It studies the key issues in tariff design in large power systems to understand how the concept of tariff design can be translated to cost allocation in an ICES. It provides guidelines for both community managers and community members to understand how the costs should be allocated.

- *Approaches for cost allocation in ICESs.* By reviewing the most widely used cost allocation methods adopted in tariff design in ICESs, we derive cost allocation approaches for ICESs. In this regard, it provides various possible methods for allocating costs in a local community energy system with DERs.

- *Performance assessment of cost allocation methods.* Two criteria are proposed to evaluate the performance of the various cost allocation methods: cost reflectiveness and predictability, to gain insight into how well the costs are allocated and how the energy bills change in the long-term. The assessment facilitates the local community members in selecting a method that satisfies their requirements.

- *Social acceptance analysis for cost allocation in ICESs.* Social acceptance is conceptualized from the perspective of procedural and distributive justice, to make sure the process and the results of cost allocation are fair and socially acceptable to local community members. Multi-group multi-criteria decision-making method is adopted as the tool to select a cost allocation method that is socially acceptable to local community members. It is able to provide decision-making on a cost allocation method with various degrees of preference from multi-criteria and multi-group decision-making perspectives. This approach can be applied directly to any local energy system without regulation, which is expected to allocate costs among local community members in a socially acceptable manner.

7.4. Future work recommendations

According to the extensive discussion on the barrier and enablers for cost allocation in ICESs in Section 6, it is concluded that there are still several aspects related to cost allocation in ICESs have not been addressed adequately in this thesis. Based on this, the following directions for future research are discussed in this section.

7.4.1. Local policy package design

Local regulations, policy, and institutional design are required to support that local community members are entitled to participate in the decision-making process of cost allocation in ICESs while maintaining their rights and obligations as final consumers. The key factors that affecting procedural justice, such as transparency, non-discrimination, and others, should be well-followed by the local manager or community management team, to make sure that local community members are actively involved in the process of cost allocation. Besides this, local authorities should support such local activities as collectively and individually investment, energy sharing and exchange activities, necessary support from the grid and among others, to make sure the successful implementation of such projects. It, therefore, requires to design specific policy packages from the institutional design perspective.

7.4.2. Local demand response

The research up to now only considers how to allocate costs in a socially acceptable manner, however, other issues such as local demand response is not explained. It is not clear how demand response activity can be achieved in ICESs, such as monetary reward or real-time pricing. The mechanism could be local community members who consume energy at peak generation hours get revenues and who consume energy at off-peak generations hours get punishments. Based on the given cost allocation mechanism, it is worth investigating how to incentivize local community members to participate in demand response activities and to further optimize their energy bills. Furthermore, it is also essential to study how the local demand response program could contribute to the optimal operation of ICESs in the short-term and sustainable investment and development of ICESs in the long-term. This would be another interesting topic to explore in future research.

7.4.3. The impact of joining or leaving the community on cost allocation

Another issue that is not addressed in the thesis is the impact of joining or leaving the community on the formulation of the energy system and the selection of cost allocation methods. On one hand, when new local community members join the ICES, the existing generation capability may not satisfy the load demand. The community either invests in local DERs or buys electricity directly from the grid. Then the cost structure of the energy system and the existing cost allocation method may work or not work efficiently. Therefore, it is necessary to investigate its impact to see if it is required to change the current cost allocation method. On the other hand, when the existing local community members leave the ICES, demand reduces in the energy system. It is apparent that local community members will burden more costs when the ICES works in off-grid mode with fewer members. However, when the ICES works in grid-connected mode, it can sell surplus generation to the grid to get some revenues. It is unsure whether the current cost allocation method still works or not. Therefore, it is necessary to investigate the impact of joining or leaving the community on the selection of the cost allocation method.

7.4.4. Energy exchange mechanism

The energy exchange mechanism taken in this research is community-based P2P trading that prosumers sell their surplus energy to the community at one price and buy deficit energy from the community at another price. However, it remains unclear what are the impacts on the energy bills of local community members if the energy exchange prices change. Another aspect that is interesting to investigate is what are the impacts of different energy exchange mechanisms on the individual energy bills and the whole system. Furthermore, it is worth exploring which energy exchange mechanism is the most attractive for the local community members.

7.4.5. Cost allocation methods

In this thesis, ten methods are proposed as the possible alternatives to allocate costs in ICESs. There could be other options, which are not addressed in this thesis. In addition, considering the given methods, a lot of modifications can be applied to them to create more options. For example, the chosen allocating coefficient - for methods with two or more charging components is the load factor. Further research is recommended to reveal the impact of flexible coefficients on the results of cost allocation in ICESs and to see if these can improve cost reflectiveness and predictability when compared to the methods with one single charging component. In addition, the two-part pricing and multi-part pricing use flat energy and capacity price, which is independent of time difference. The combination of time-variant energy and capacity price is not considered in this thesis. Many modifications can be made to the cost allocation methods presented here. They provide more options for local community members to select.

7.4.6. Multi-group and multi-criteria decision-making

In this thesis, we analyzed social acceptance of cost allocation in ICESs from a multi-group and multi-criteria decision-making perspective. Local community members are classified into several groups according to their major preferences, which are explicitly defined in the study. However, their major preferences might be ambiguous in reality, therefore, the method that take ambiguity into account can be applied in future work to study social acceptance. Besides, seven decision-making groups are classified in this research based on the criteria defined in the dimension of distributive justice. It is possible to add or reduce the decision-making groups according to the preferences of local community members. Furthermore, we use quantitative method to help local community members to take decision-making to select a socially acceptable cost allocation method. It is interesting to adopt qualitative research methodology, such as questionnaires and surveys, to analyze the preferences and requirements of local community members.

7.5. Final remarks

With the growing demand for energy transition, this thesis provides a view of how cost allocation can facilitate the success of local community energy systems from a socio-economic perspective. Although it is challenging to allocate costs in a socially acceptable manner in the context of local community energy systems without regulation, this thesis provides a systematic framework and practical methods to allocate costs in ICESs. The approach presented can facilitate the local community manager and members in allocating costs in a socially acceptable manner. Local community members can actively participate in the decision-making process to express their opinions and preferences. And the methodology can be directly applied to any local community energy system with similar characteristics to ICESs. Although much work still needs to be done, this work has hopefully contributed to understanding the importance of socially acceptable cost allocation to ensure a successful implementation of ICESs. Thus, it can contribute to the formulation of local community energy markets and supporting the energy transition.

A

Chapter 2 nomenclature

Nomenclature

P_f	Flat energy price [€/kWh]
TC	Total cost [€]
$E_i(t)$	Energy consumption at hour t of customer i [kWh]
N	The number of customers
T	Time period [hours]
C_i	The energy bill of customer i [€]
TC_{base}	The costs allocated to base hours [€]
TC_{peak}	The costs allocated to peak hours [€]
TC_1	The costs for satisfying base demand [€]
TC_2	The costs for satisfying peak demand over base demand level [€]
T_{base}	Off-peak hours [hours]
P_{base}	The energy prices in base hours [€/kWh]
P_{peak}	The energy prices in peak hours [€/kWh]
E_{base}	Total energy consumption in base hours [kWh]
E_{peak}	Total energy consumption in peak hours [kWh]
$C_i(t)$	The hourly energy bill for customer i [€]
MC	The marginal cost [€/kW(h)]
Q	The quantity of energy [kWh] or capacity [kW] supplied
$TC(Q)$	The cost function [€]

IC	The incremental cost [€/kW]
$f_{1,\ i}$	The first two-part allocation factor of customer i
$f_{2,\ i}$	The second two-part allocation factor of customer i
$E_{ave,\ i}$	The average demand of customer i [kWh]
$E_{peak,\ i}$	The peak demand of customer i [kWh]
$E_{exc,\ i}$	The excess demand of customer i [kW]
lf	Load factor
E_{peak}	The system peak demand [kWh]
P_i	The electricity price for customer group i [€/kWh]
MC_i	The marginal cost for customer group i [€/kWh]
λ	The Lagrange multiplier
η_i	The price elasticity of demand associated with customer group i
P_{TN}	The transmission network price [€/kW]
$E_{tran,\ i}$	The peak demand of transaction i [kW]
K	The number of transactions
$E_{path,\ i}$	The magnitude of power signed in the contract for path i [kW]
R	The number of contract paths
PX_i	MW-mile value [MW $\cdot$ mile]
L_i	The geographical distance between seller and buyer of transaction i [mile]
$E_{tr,\ i}$	The magnitude of the transacted power [kW]
Z	The set of all circuits
c_j	The cost of circuit j per MW per mile [€/MW $\cdot$ mile]
$L_{i,j}$	The length of circuit j of transaction i [mile]
$E_{i,j}$	The power flow in circuit j caused by transaction i kW
P_{CP}	The coincident peak demand charge [€/kW]
$E_{CP,\ i}$	The peak demand of customer i occurring at the system peak hours [kW]
P_{NCP}	The non-coincident peak demand charge [€/kW]

B

Chapter 3 nomenclature

Nomenclature

C	Energy cost per customer [€/customer]
TC	Total costs [€]
N	The number of customers
P_f	Flat energy price [€/kWh]
$E_i(t)$	Energy consumption at hour t by household i [kWh]
T	Time period [hours]
P_{base}	Energy price in off-peak hours [€/kWh]
P_{peak}	Energy price in peak hours [€/kWh]
C_{base}	Costs in off-peak hours [€]
C_{peak}	Costs in peak hours [€]
lf	Load factor
T_{base}	Off-peak hours [hours]
T_{peak}	Peak hours [hours]
$E(t)$	The hourly energy consumption at hour t [kWh]
$C_i(t)$	Energy cost at hour t for user i [€]
$E_{base}(t)$	Energy consumption in off-peak hours [kWh]
$E_{peak}(t)$	Energy consumption in peak hours [kWh]

CS_i	Subscribed capacity of DERs by household i [kW]
P_{CS}	Subscribed capacity price [€/kW]
P_{CP}	Coincident peak capacity price [€/kW]
$E_{CP,i}$	Coincident peak demand by household i [kW]
P_{NCP}	Non-coincident peak capacity price [€/kW]
$E_{NCP,i}$	Non-coincident peak demand by household i [kW]
P_{ave}	Energy price for consumption below the threshold [€/kWh]
P_{exc}	Energy price for consumption exceeds the threshold [€/kWh]
T_{ave}	Hours for consumption below the threshold [hours]
T_{exc}	Hours for consumption exceeds the threshold [hours]
$E_{ave}(t)$	Energy consumption below the threshold [kWh]
$E_{exc}(t)$	Energy consumption exceeds the threshold [kWh]
E_{th}	Threshold value [kWh]
$f_{1,i}$	The first allocation factor for user i
$f_{2,i}$	The second allocation factor for user i
f	Allocation coefficient
$E_{ave,i}$	Average demand of user i [kW]
$E_{exc,i}$	Excess demand of user i [kW]
$E_{peak,i}$	Peak demand of user i [kW]
C_i	The energy cost of user i
P_C	Capacity price [€/kW]
P_E	Average energy price [€/kWh]
TC_E	Costs allocated to energy component [€]
TC_C	Costs allocated to capacity component [€]
P_N	Customer service price [€/customer/year]
TC_S	Costs allocated to customer service component [€]
TC_{E+C}	Costs allocated to energy and capacity components [€]

C

Chapter 4 nomenclature

Nomenclature

$D_i(t)$	Energy consumption for user i at hour t [kWh]
$D(t)$	Total energy consumption for all users at hour t [kWh]
$E_{RES}(t)$	Energy generation from RESs at hour t [kWh]
IC_{PV}	Installed capacity of PV [kW]
IC_{WT}	Installed capacity of wind turbine [kW]
$P_{PV}(t)$	PV generation per capacity at hour t [kWh/kW]
$P_{WT}(t)$	Wind turbine generation per capacity at hour t [kWh/kW]
$E_{dif}(t)$	Energy difference between generation and demand at hour t [kWh]
$E_B(t)$	Energy state of storage at hour t
$E_B(t+1)$	Energy state of storage at hour $t+1$
E_{Bmin}	Minimal energy state of storage [kWh]
E_{Bmax}	Maximal energy state of storage [kWh]
B_e	Charging and discharging efficiency of storage
$E_{ex,\ grid}(t)$	Energy exchange with the grid at hour t [kWh]
$CRI_{i,j}$	Cost reflectiveness index for user i under method j
$C_{i,j}$	Annual cost for user i under method j [€]
$C_{i,DER}$	Annual cost for user i for its individual energy system [€]
$CPI_{i,j}$	Cost predictability index for user i under method j
$C2_{i,j}$	Annual cost for user i under method j in year 2 [€]
$C1_{i,j}$	Annual cost for user i under method j in year 1 [€]

D

Chapter 5 nomenclature

Nomenclature

var_{ref/pre_j}	The variance of cost reflectiveness (or predictability) of method j
$ref/pre_{i,j}$	The index for cost reflectiveness (or predictability) of method j for user i
Q	The number of users
$v_{m,n}$	The decision-making matrix of each criteria m for each alternative n
M	The set of criteria
N	The set of alternative
$NV_{cau,n}$	The normalization value of cost causality for method n
$v_{cau,n}$	The value of cost causality for method n
$v_{cau,n,min}$	The minimal value of cost causality for method n
$v_{cau,n,max}$	The maximal value of cost causality for method n
$NV_{ref/pre,n}$	The normalization value of cost reflectiveness (or predictability) for method n
$v_{ref/pre,n}$	The variance value of cost reflectiveness (or predictability) for method n
$v_{ref/pre,n,max}$	The maximal value of cost reflectiveness (or predictability) for method n
$v_{ref/pre,n,min}$	The minimal value of cost reflectiveness (or predictability) for method n
$R^a_{m,n}$	The weighted normalized decision matrix for each decision-making group a
A	The set of decision-making group
w^a_m	The weight for criteria m for decision-making group a

P_m^{a+}	The best point regarding each criterion m for each decision-making group a
P_m^{a-}	The worst point regarding each criterion m for each decision-making group a
S_n^{a+}	The positive distance for each alternative n for each decision-making group a
S_n^{a-}	The negative distance for each alternative n for each decision-making group a
CC_n^a	The normalized CC for each alternative n for each decision-making group a
ACC_n^a	The absolute value of CC for each solution n for each decision-making group a
$CC_n^{geo,\ ave}$	The average value of CC score

E

Acronyms

Nomenclature

ICESs	Integrated community energy systems
ToU	Time-of-use
DERs	Distributed energy systems
RESs	Renewable energy sources
EMS	Energy management system
CCHP	Combined cooling, heating and power
P2G	Power to gas
CP	Coincident peak
NCP	Non-coincident peak
O&M	Operation and maintenance
P2P	Peer to peer
PV	Photovoltaic
AHP	Analytic hierarchy process
ELECTRE	Elimination et choice translating reality
PROMETHEE	Preference ranking organization method for enrichment evaluation
TOPSIS	Technique for order preference by similarity to ideal solution
MCDM	Multi-criteria decision-making
CC	Coefficient of closeness

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4. Li, N., Hakvoort, R. A., Lukszo, Z. (2021). Cost allocation in integrated community energy systems - Performance assessment. Applied energy, 37, 118155.

3. Li, N., Hakvoort, R. A., Lukszo, Z. (2021). Cost allocation in integrated community energy systems - A review. Renewable and Sustainable Energy Reviews, 144, 111001.

2. Li, N., Hakvoort, R. A., Lukszo, Z. (2021). Cost allocation in integrated community energy systems - social acceptance. Sustainability, 13(17), 9951.

1. Li, N., Hakvoort, R. A., Lukszo, Z. (2020, October). Segmented energy tariff design for flattening load demand profile. In 2020 IEEE PES Innovative Smart Grid Technologies Europe (ISGT-Europe) (pp. 849-853). IEEE.

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