Incorporating indirect costs into energy system optimization models

Application to the Dutch national program Regional Energy Strategies

Wang, Ni; Verzijlbergh, Remco A.; Heijnen, Petra W.; Herder, Paulien M.

DOI
10.1016/j.energy.2023.127558

Publication date
2023

Document Version
Final published version

Published in
Energy

Citation (APA)
Wang, N., Verzijlbergh, R. A., Heijnen, P. W., & Herder, P. M. (2023). Incorporating indirect costs into energy system optimization models: Application to the Dutch national program Regional Energy Strategies. *Energy*, *276*, Article 127558. https://doi.org/10.1016/j.energy.2023.127558

Energy 276 (2023) 127558

Contents lists available at ScienceDirect

Energy

journal homepage: www.elsevier.com/locate/energy

Incorporating indirect costs into energy system optimization models: Application to the Dutch national program Regional Energy Strategies

Ni Wang [a,b,*], Remco A. Verzijlbergh [a], Petra W. Heijnen [a], Paulien M. Herder [c]

[a] Faculty of Technology, Policy and Management, Delft University of Technology, Jaffalaan 5, 2628BX Delft, The Netherlands
[b] TNO Energy Transition Studies, Radarweg 60, 1043NT Amsterdam, The Netherlands
[c] Faculty of Applied Sciences, Delft University of Technology, Lorentzweg 1, 2628CJ Delft, The Netherlands

ARTICLE INFO

Keywords:
Energy system optimization model
Indirect costs
Energy markets
Energy system planning
Willingness to pay
Transaction costs

ABSTRACT

Energy system optimization models are widely used to aid long-term investment decision-making for energy systems. From a socio-technical system viewpoint, existing models focus on the cost modeling of the technical subsystem, while the indirect costs of the social subsystem are not often modeled. This paper incorporates indirect costs into such a model, including those associated with generation capacity, energy production, and bilateral trades, respectively. As a proof-of-concept, the model has been applied to a case study for the Dutch power system, reflecting the Dutch national program Regional Energy Strategies, where regions collectively plan wind and solar energy capacities. We conclude that incorporating indirect costs significantly changed the optimal investment capacities and the associated costs for the regions compared to benchmark results from the conventional models. Furthermore, in this case study, a potential free-rider problem with regard to the national climate target occurs. Our model is used as a negotiation simulator to inform the regions about the hypothetical free-riding behaviors and thus helps to achieve a socially acceptable investment plan. The proposed energy system optimization model with indirect costs goes beyond the prevalent cost-minimization paradigm, and can be used to study transaction costs, trading barriers, and willingness to pay.

1. Introduction

Energy system optimization models (ESOM) refer to optimization models that aim to find the optimal capacity expansion of generation technologies, and transmission networks [1]. The objective is usually to minimize the total system cost while satisfying a number of constraints such as energy balance, generation limits, and network limits. The results of the models are possible scenarios to achieve certain carbon/renewable energy sources (RES) targets that the energy system might evolve into [2]. Such models are often used by policymakers because they serve as a benchmark to help them make decisions on potential policy changes in view of the modeling outcomes, i.e., optimal capacity expansion and the associated costs. As an example, these models may be used to assess the business opportunities of RES, and whether policy support is needed. For high-RES energy systems, numerous models are built in recent years. Groissböck (2019) gave an overview of open-source energy system optimization tools [3] based on their maturity.

To better use of the model, it is desired that the different domain knowledge is combined in a meaningful way with concrete scoping [4]. From a socio-technical perspective, the energy system comprises a technical subsystem and a social subsystem. Due to the techno-economic nature of ESOM, the parameterized costs in the existing models are mostly limited to the technical side. Deng and Lv (2020) reviewed existing models based on components, i.e., objective functions, constraints, and parameters [5]. It was found that the cost structure consists mostly of capital costs and operation & maintenance costs both on the supply and demand side including the integration costs such as the curtailment costs. However, the relevant costs related to the social subsystem are largely ignored. Although the social subsystem can be modeled by simulations models [6], finding the optima considering the social subsystem can bring different insights. As the interaction between the social and technical subsystem becomes increasingly important [7], these non-technical factors need to be modeled in ESOM [8].

Firstly, there are social costs incurred by social resistance to controversial technologies such as wind energy. From the modeling point of view, the social resistance creates social costs on top of the capital costs. Secondly, there are taxes or subsidies imposed on energy production. In reality, these costs are reflected in market prices as producers would add these costs to the marginal costs of energy production. Thirdly, there are indirect costs in bilateral trades. ESOM are known to represent the investment equilibrium under a short-term pool market [9],

* Corresponding author at: Faculty of Technology, Policy and Management, Delft University of Technology, Jaffalaan 5, 2628BX Delft, The Netherlands.
E-mail address: wangni0205@gmail.com (N. Wang).

https://doi.org/10.1016/j.energy.2023.127558
Received 29 October 2022; Received in revised form 11 March 2023; Accepted 17 April 2023
Available online 21 April 2023

Nomenclature

Parameters

Δ_l	Length of line l
Φ_n	Percentage of trades in the bilateral market at node n
CAP^{CO_2}	Carbon market cap [ton]
A_l	Annuity factor of line l
A_i	Annuity factor of technology i
B_i	Variable costs of technology i [€/MWh]
C_l	Fixed costs of line l [€/MW/km]
C_i	Fixed costs of generation and storage conversion technology i [€/MW]
CS_i	Fixed costs of storage technology i [€/MWh]
$E^{\text{bilateral-ic}}_{n,m}$	Product differentiation value from node n towards node m [€/MWh]
$E^{\text{capacity-ic}}_{i,n}$	Unit social cost for technology i at node n [€/MW]
$E^{\text{production-ic}}_{i,n}$	Carbon tax/RES subsidy for technology i at node n [€/MWh]
H^{in}_i	Charging efficiency of storage technology i
H^{out}_i	Discharging efficiency of storage technology i
K_l	Existing capacity of line l [MW]
$K_{i,n}$	Existing capacity of technology i at node n [MW]
$PTDF$	Power Transfer Distribution Factors matrix
W_i	Emission of fossil-fueled technology i [ton/MWh]

Sets

$\mathcal{G}$	Set of generation technologies
$\mathcal{L}$	Set of lines
$\mathcal{N}$	Set of nodes
$\mathcal{R}$	Set of fossil-fueled generation
$\mathcal{S}$	Set of storage technologies
$\mathcal{T}$	Set of time steps
ω_n	Set of neighbors of node n on the communication graph

Variables

$\lambda^{\text{bilateral}}_{n,m,t}$	Bilateral trading price between node n and node m at time step t [€/MWh]
$\lambda^{\text{grid}}_{n,m,t}$	Grid price between node n and node m at time step t [€/MWh]
$\lambda^{\text{pool}}_{n,t}$	Pool trading price at node n at time step t [€/MWh]
$f_{l,t}$	Energy flow at line l at time step t [MWh]
$k^{\text{storage}}_{i,n}$	Investment capacity of storage technology i at node n [MWh]
k_l	Investment capacity of line l [MW]
$k_{i,n}$	Investment capacity of generation and storage conversion technology i at node n [MW]
$p^{\text{bilateral}}_{n,m,t}$	Bilateral trades from node n to node m at time step t [MWh]
$p^{\text{in}}_{i,n,t}$	Charging to storage of storage technology i at node n at time step t [MWh]
$p^{\text{out}}_{i,n,t}$	Discharging from storage of storage technology i at node n at time step t [MWh]
$p^{\text{pool}}_{n,t}$	Pool trades at node n at time step t [MWh]
$p_{i,n,t}$	Produced energy from technology i from node n at time step t [MWh]
$soc_{i,n,t}$	Energy in storage of storage technology i at node n at time step t [MWh]
$z^{\text{bilateral}}_{n,m,t}$	Arbitrage energy from the transmission system operator (TSO) from node n to node m at time step t in the bilateral market [MWh]
$z^{\text{pool}}_{n,t}$	Arbitrage energy from the TSO at node n at time step t in the pool market [MWh]

while the future markets, including bilateral markets, are usually not included. According to the report on European electricity markets [10], bilateral contracts account for a large portion of the energy trades. So by not considering bilateral trading, only a small portion of the traded volumes are modeled. In pool markets, electricity is traded homogeneously. Compared to pool-based trades, bilateral trades depend more on the bilateral relationship, e.g., the willingness to pay of the buyers. This relationship may be parameterized as an indirect cost perceived by the trading parties, and thus can be considered as a form of externality for the prevalent pool market.

1.1. State-of-the-art of the cost modeling in energy system optimization models

In the literature, social costs are modeled by different approaches. However, their formulation and applications in ESOM are rarely seen. Dresler et al. (2011) proposed a welfare-economic approach to determine the spatial allocation of wind energy, where social cost consisting of production cost and external costs are considered [11]. The external costs are regarded as the monetary costs on the environment and people's preferences. The authors further combined different approaches for the same purpose in [12]. Shih et al. (2016) quantified the monetary values of social costs for the most commonly used energy sources in the world [13]. Salomon, Drechsler, and Reutter (2020) used an ecological-economic model for the assessment of the social costs of wind energy to identify the effects of policies [14]. Krumm, Süsser, and Blechinger (2022) gave an overview of the representation of social factors in ESOM [15]. It was found that the social costs are either modeled implicitly as technical-social potentials of technology, e.g., see [16] where different land-use potentials are discussed to proxy the social resistance of wind energy, or discussed only qualitatively in [17]. Despite the importance of accounting for social costs to wind energy development [18], most existing ESOM do not explicitly include this type of cost.

Since ESOM are widely used to support policy-making, taxes and subsidies are commonly modeled by ESOM. Due to its wide application, only a selection of the relevant literature is described. Liu et al. (2013) compared the effects of taxes and direct interventions of emissions using an energy system model [19]. Yazdanie, Densing, and Wokaun (2017) evaluated the influences of several national energy policies including carbon taxes in an optimization model [20]. Carbon and local pollutant emission taxes were modeled in the objective functions of the model in [21]. Li, Li, and Li (2020) used optimization to reveal the effects of policy uncertainties of carbon taxes and power substitution policies [22]. Subsidies were modeled in an ESOM proposed by [23] where different parameterizations were investigated. Yin et al. (2021) quantitatively studied subsidies and risk preferences of actors using scenario analysis [24].

Bilateral trading is generally known as a bilateral market. Because bilateral trading has not been incorporated in ESOM, the literature on bilateral market modeling beyond the field of ESOM is reviewed. Since the liberalization of the electricity sector, various bilateral market models were proposed to calculate the market equilibrium under different assumptions. These studies focus on producers and their behaviors in the wholesale market. One of the pioneering works in this field is [25], where Cournot models of imperfect competition were used to simulate the bilateral market. This model was later modified to study generation investment while different carbon policies were evaluated in [26]. Apart from the equilibrium analysis, research efforts have also been made on individual generators' perspectives to model bilateral contracts. In [27], an optimization model was proposed for the optimal planning for distributed generations under competitive market auctions and fixed bilateral contract scenarios. Other market players than generators such as retailers, prosumers, and energy communities have also been studied. For example, Karandikar, Khaparde, and Kulkarni (2010) presented a methodology to evaluate bilateral contracts of retailers from a risk perspective [28]. Tang et al. (2017) proposed a game-theoretical model to describe the competition for bilateral contracts among generation companies and large consumers [29]. Pourakbari-Kasmaei et al. (2020) modeled the trilateral interactions among an integrated community energy system, prosumers, and the wholesale electricity market [30]. Bilateral contracts were also modeled in combination with demand response to find the optimal energy storage sizing in [31]. In terms of the modeling methods, agent-based modeling is sometimes used to model bilateral contracts. In the review of [32] on electricity systems models, two agent-based modeling platforms that incorporate bilateral contracts, EMCAS and GTMax, are discussed. Imran et al. (2020) developed utility-based and adaptive agent-tracking strategies for bilateral negotiations [33]. In recent years, with the increasing penetration of distributed energy sources, peer-to-peer (P2P) markets have emerged as the next-generation market designs. In these markets, bilateral trading is considered one of the most promising P2P market mechanisms [34] and is thus commonly modeled. Particularly, bilateral trades can be associated with the preferences of the trading parties. To represent this feature, terms such as heterogeneous preferences [35], product differentiation [36] and energy classes [37] have been used. Among these features, product differentiation is a generic mathematical formulation that can be used for various purposes [38], e.g., Baroche et al. (2019) used it to account for exogenous network tariffs in P2P markets [39].

1.2. Scientific and societal relevance

This paper presents an energy system optimization model with indirect costs focusing on those associated with bilateral trading. The scientific and societal relevance of this study is as follows.

The literature review shows that although ESOM have been used to study taxes and subsidies, they do not include the social costs and indirect costs in bilateral trades. To fill this research gap, a generic formulation with regard to indirect costs associated with generation capacity, energy production, and bilateral trades, respectively, is presented in this paper.

One of the critiques of the conventional ESOM is that only techno-economic aspects are considered but social and behavioral aspects are largely ignored [40]. From the societal perspective, our model with indirect costs goes beyond the prevalent cost-minimization paradigm and is able to model aspects such as social costs, transaction costs, trading barriers, and willingness to pay. Considering a wind system that requires large investments from a cost-optimal perspective. In practice, however, social resistance against wind power may hamper investment in many locations. Nevertheless, some locations may still invest due to less resistance or government mandate. In this case, the locations that do not invest may benefit from the cheap electricity produced by wind power while not paying the corresponding social costs. Such cases can be studied using our proposed model with indirect costs, but they cannot be investigated using the prevalent cost-optimal models without indirect costs. This approach will be elaborated in the case study, where the proposed model is a negotiation simulator to inform the parties about their hypothetical free-riding behaviors and helps to reach socially acceptable investments with respect to the distribution of wind energy.

Accordingly, the contributions of this paper are two-fold. First, there is a methodological contribution to the state-of-the-art of energy system optimization models. Previously, only capital costs and operation & maintenance costs are considered. In this paper, a generic formulation for indirect costs is presented, which can model the social costs of generation investment, taxes, subsidies, and bilateral trading costs. Second, the paper offers practical implications on how socially acceptable investments can be reached beyond the cost-minimization paradigm. A proof-of-concept case study for the Dutch energy system is conducted where the model is used as a negotiation simulator to treat a hypothetical free-rider problem.

The paper is structured as follows. First, the models are presented in Section 2. In Section 3, a case study of the Netherlands to illustrate the model is introduced. The results are discussed in the next section. Section 5 presents conclusions.

2. Proposed model

The proposed energy system optimization model is a linear programming model which aims to find the cost-optimal investment planning of the power system with carbon constraints, i.e., generation and network expansion. It models a long-term investment equilibrium assuming perfectly competitive markets with explicit indirect cost terms for generation capacity, energy production, and bilateral trades, respectively. The geographical scope is the national level and above, and the network refers to the transmission grid. This model is suitable for power systems with a high share of RES. Storage technologies are also modeled to deal with the intermittency of RES. CO_2 targets are modeled, allowing for policy-relevant analysis regarding emission goals. Two types of trades, pool-based and bilateral, are differentiated. In the pool market, energy is traded in a pool homogeneously. In the bilateral market, energy is traded bilaterally and heterogeneously with indirect costs. A communication graph is pre-defined where the edges connect the pair of nodes that may trade energy with each other.

The starting point of this refined model is a conventional ESOM without indirect costs proposed by Wang et al. (2020) [16]. From the cost modeling perspective, the new model incorporates indirect costs by reconstructing the core components of the model, i.e., the objective function, the nodal balance constraints, and the market balance constraints. The proposed model only inherits the modeling of the generation and storage components from the previous work, the network constraints have been improved as well to allow more accurate modeling of the power flows.

In this study, lowercase symbols are used for variables, and uppercase symbols are used for parameters. Dual variables are expressed using Greek letters and are placed after the colons in the constraints. n is the index for nodes $\mathcal{N}$. ω_n is the set of the communication graph for node n. i is the index for generation technologies $\mathcal{G}$ and storage technologies $\mathcal{S}$. l is the index for transmission lines in the existing line set $\mathcal{L}$. t represents a time step in the set of total time steps $\mathcal{T}$.

2.1. Decision variables

The decision variables regarding generation and storage include the investment capacities $k_{i,n}$ of generation and storage conversion i, the investment capacities $k_{i,n}^{\mathrm{storage}}$ of storage i, the energy production $p_{i,n,t}$ from technology i at time step t, the bilateral trades $p_{n,m,t}^{\mathrm{bilateral}}$ from node n to node m at time step t, the pool trades $p_{n,t}^{\mathrm{pool}}$ for node n at time step t, the state-of-charge $soc_{i,n,t}$ of storage i for node n at time step t, storage discharging $p_{i,n,t}^{\mathrm{out}}$ of storage i for node n at time step t, and storage charging $p_{i,n,t}^{\mathrm{in}}$ of storage i for node n at time step t.

The decision variables regarding networks include the investment capacity k_l in line l, the bilateral trades $z^{\text{bilateral}}_{n,m,t}$ from n to m at time step t, the pool-based trades $z^{\text{pool}}_{n,t}$ for n at time step t, and the energy flow $f_{l,t}$ in line l at times step t.

2.2. Objective function

The objective is to minimize the system annualized cost related to the investment and the operation of its generation, storage, and transmission technologies.

$$\min \sum_{n\in\mathcal{N}}\sum_{i\in(\mathcal{G}+\mathcal{S})}\frac{C_i k_{i,n}}{A_i}+\sum_{n\in\mathcal{N}}\sum_{i\in\mathcal{S}}\frac{CS_i k^{\text{storage}}_{i,n}}{A_i}+\sum_{n\in\mathcal{N}}\sum_{t\in\mathcal{T}}\sum_{i\in\mathcal{G}}B_i p_{i,n,t} + \sum_{l\in\mathcal{L}}\frac{\Delta_l C_l k_l}{A_l} \tag{1}$$

$$+\sum_{n\in\mathcal{N}}\sum_{i\in\mathcal{G}}E^{\text{capacity-ic}}_{i,n}k_{i,n}+\sum_{n\in\mathcal{N}}\sum_{i\in\mathcal{G}}\sum_{t\in\mathcal{T}}E^{\text{production-ic}}_{i,n}p_{i,n,t} + \sum_{n\in\mathcal{N}}\sum_{t\in\mathcal{T}}\sum_{m\in\omega_n}E^{\text{bilateral-ic}}_{n,m}|p^{\text{bilateral}}_{n,m,t}| \tag{2}$$

The first part (1) is the cost items modeled in the existing ESOM, including fixed costs and variable costs of the considered technologies. A_i is the annuity factor for technology i. C_i, CS_i, and C_l are the fixed costs for generation i, storage i, and transmission network l respectively. B_i is the variable cost for technology i. Δ_l is the length of line l.

The second part (2) represents the indirect costs, which consist of three parts. The first two parts refer to the indirect costs directly related to the generation capacity and the energy production, respectively. One example is the social costs incurred by the social resistance against wind turbines, then $E^{\text{capacity-ic}}_{i,n}$ refers to the unit social cost of wind turbines at node n. $E^{\text{production-ic}}_{i,n}$ represents the indirect cost associated with the energy production, such as carbon costs or RES subsidies. The final indirect cost is formulated as a product differentiation term for every bilateral trade. See e.g., [36] for an application of this term in the context of P2P trading. It is defined as a general economic cost term related to bilateral trades because the meaning of the costs depends on the interpretation. On the one hand, it may represent exogenous charges associated with the bilateral trades, such as transaction costs, tax payments, and network charges. On the other hand, it could be viewed as an improved utility function, representing the willingness to pay for the bilateral trades. These two interpretations will be further illustrated and discussed in the case study in Section 4.

2.3. Constraints

The optimization model has the following set of constraints. Nodal balance constraints denote the physical energy balance at each node. Market balance constraints ensure the energy and carbon balances from the economic perspective. Network constraints lay out the power flow calculations. Generation and storage constraints specify the technical conditions of generation and storage units.

2.3.1. Nodal balances

(3) and (4) are nodal energy balance constraints. The net power injection $\sum_{i\in\mathcal{G}}p_{i,n,t}-D_{n,t}+\sum_{i\in\mathcal{S}}(p^{\text{out}}_{i,n,t}-p^{\text{in}}_{i,n,t})$ is divided into two parts: one for the trading in the bilateral market and the other for trading in the pool. On the right-hand side of (3) is the sum of all bilateral trades for node n.

$$\Phi_n(\sum_{i\in\mathcal{G}}p_{i,n,t}-D_{n,t}+\sum_{i\in\mathcal{S}}p^{\text{out}}_{i,n,t}-\sum_{i\in\mathcal{S}}p^{\text{in}}_{i,n,t})=\sum_{m\in\omega_n}p^{\text{bilateral}}_{n,m,t},\forall t\in\mathcal{T},\forall n\in\mathcal{N} \tag{3}$$

$$(1-\Phi_n)(\sum_{i\in\mathcal{G}}p_{i,n,t}-D_{n,t}+\sum_{i\in\mathcal{S}}p^{\text{out}}_{i,n,t}-\sum_{i\in\mathcal{S}}p^{\text{in}}_{i,n,t})=p^{\text{pool}}_{n,t},\forall t\in\mathcal{T},\forall n\in\mathcal{N} \tag{4}$$

Φ_n is a parameter between 0–1 determined by the node n itself, indicating the percentage of its net energy that n would like to trade bilaterally. The rest will be traded in the pool. This suggests that one only has to decide ex-ante how much to trade in total in the bilateral market and the pool market, without determining precisely who to trade with and how much in the bilateral market. Depending on the product differentiation, the model will help the nodes to find the optimal trading partners and the associated trading volumes. If the trading partners and the associated trading volume are fixed ex-ante, then there are no further decisions to be made, and the amount could be deducted from the demands directly. Furthermore, this model formulation is flexible in the sense that by changing the value of this parameter, a full pool market representation(when $\Phi_n = 0$), a full bilateral market representation (when $\Phi_n = 1$), or the mixed market representation (when $0 < \Phi_n < 1$) can be modeled.

2.3.2. Market balances

(5) is the reciprocity constraint for bilateral trades, showing that the bilateral trades should be equal in quantity, where the dual variable $\lambda^{\text{bilateral}}_{n,m,t}$ is the bilateral trading price. (6) and (7) are the energy balance constraints between the nodes and the TSO, where the dual variables are the grid price $\lambda^{\text{grid}}_{n,m,t}$ for the bilateral trade and the pool electricity price $\lambda^{\text{pool}}_{n,t}$ for the pool-based trade, respectively. As a result, the energy prices and the grid prices are determined in this optimization problem endogenously.

A cap-and-trade system for the carbon market is modeled. (8) gives the cap for all the carbon emissions. W_i is the emission for technology i, and the dual variable λ^{CO_2} is the carbon price.

$$p^{\text{bilateral}}_{n,m,t}=-p^{\text{bilateral}}_{m,n,t},\forall n\in\mathcal{N},\forall m\in\omega_n,\forall t\in\mathcal{T}:\ \lambda^{\text{bilateral}}_{n,m,t} \tag{5}$$

$$p^{\text{bilateral}}_{n,m,t}=z^{\text{bilateral}}_{n,m,t},\forall n\in\mathcal{N},\forall m\in\omega_n,\forall t\in\mathcal{T}:\ \lambda^{\text{grid}}_{n,m,t} \tag{6}$$

$$p^{\text{pool}}_{n,t}=z^{\text{pool}}_{n,t},\forall n\in\mathcal{N},\forall t\in\mathcal{T}:\ \lambda^{\text{pool}}_{n,t} \tag{7}$$

$$W_i\sum_{n\in\mathcal{N}}\sum_{t\in\mathcal{T}}\sum_{i\in R}p_{i,n,t}=\text{CAP}^{CO_2}:\ \lambda^{CO_2} \tag{8}$$

2.3.3. Network constraints

The energy flow is modeled using direct current power flow equations, which is a common practice in planning models. In (9), the flow $f_{l,t}$ is calculated based on the Power Transfer Distribution Factors matrix and the total net injection at every node $n \in \mathcal{N}$ [41]. (10) indicates the thermal limits of the energy flows, where K_l is the existing transmission capacity.

$$f_{l,t}=\sum_{n\in\mathcal{N}}PTDF_{l,n}(\sum_{m\in\omega_n}z^{\text{bilateral}}_{n,m,t}+z^{\text{pool}}_{n,t}),\forall l\in\mathcal{L},\forall t\in\mathcal{T} \tag{9}$$

$$-(k_l+K_l)\le f_{l,t}\le k_l+K_l,\forall l\in\mathcal{L},\forall t\in\mathcal{T} \tag{10}$$

2.3.4. Generation constraints

(11) indicates that the energy production is constrained by the efficiency $E_{i,n,t}$ (capacity factor in case of variable renewable energy) and the capacity of the generation technologies. Here, $K_{i,n}$ is the existing capacity, $k_{i,n}$ is the capacity to be expanded.

$$0\le p_{i,n,t}\le E_{i,n,t}(k_{i,n}+K_{i,n}),\forall i\in\mathcal{G},\forall t\in\mathcal{T},\forall n\in\mathcal{N} \tag{11}$$

2.3.5. Storage constraints

(12)–(16) are the storage constraints. (12) and (13) are for state-of-charge. Since the modeling horizon is one year, the state-of-charge is modeled as cyclic. This results in the extra constraint (13) for the state-of-charge for time step 0. (14) and (16) show the bounds for state-of-charge, storage charging, and storage discharging.

$$soc_{i,n,t}=soc_{i,n,t-1}+H^{\text{in}}_i p^{\text{in}}_{i,n,t}-\frac{1}{H^{\text{out}}_i}p^{\text{out}}_{i,n,t},\forall i\in\mathcal{S},\forall t\in\mathcal{T},\forall n\in\mathcal{N} \tag{12}$$

$$soc_{i,n,0}=soc_{i,n,t_{end}}+H^{\text{in}}_i p^{\text{in}}_{i,n,0}-\frac{1}{H^{\text{out}}_i}p^{\text{out}}_{i,n,0},\forall i\in\mathcal{S},\forall n\in\mathcal{N} \tag{13}$$

$$0 \leq soc_{i,n,t} \leq k_{i,n}^{\text{storage}} + K_{i,n}^{\text{storage}}, \forall i \in \mathcal{S}, \forall t \in \mathcal{T}, \forall n \in \mathcal{N} \tag{14}$$

$$0 \leq p_{i,n,t}^{\text{out}} \leq k_{i,n} + K_{i,n}, \forall i \in \mathcal{S}, \forall t \in \mathcal{T}, \forall n \in \mathcal{N} \tag{15}$$

$$0 \leq p_{i,n,t}^{\text{in}} \leq k_{i,n} + K_{i,n}, \forall i \in \mathcal{S}, \forall t \in \mathcal{T}, \forall n \in \mathcal{N} \tag{16}$$

3. Case study: Regional Energy Strategies in the Netherlands

In 2019, the Dutch government announced the climate agreement to reduce the Netherlands' greenhouse gas emissions by 49% by 2030 compared to 1990 levels [42]. In the electricity sector, a major focus is to increase the share of wind and solar energy, i.e., from 14.25 TWh in 2018 to 84 TWh in 2030. Accordingly, massive investments in wind and solar energy are needed. The investments are facilitated through a national program Regionale Energiestrategie (Regional Energy Strategies) [43]. In this program, the country is divided into 30 energy regions, where each region proposes its investments in onshore wind and solar energy. Meanwhile, the TSO proposes the transmission network expansion plan.

Due to land-use and social acceptance issues of wind energy, there are tensions between the national government and regional government, making it hard to transform national goals into regional proposals. The interim analysis [44] shows that the proposed production of solar energy and wind energy is comparable, despite that wind energy is cheaper. In 2021, two years after the climate agreement has been announced, a first version of the investment plan [45] was published, which finally meets the target. The process is complex and involves considerations from different dimensions where cost, land-use, and social acceptance are some of the main drivers.

Given this background, the proposed approach is used in two different ways: the first part of the case study will show the optimal investment capacity to reach the RES target in 2030. In the second part, the focus is on the investment preferences of the regions, in particular related to the wind energy investment situation. Not investing into wind energy from some regions potentially causes a free-rider problem in terms of the joint investment target because others may be forced to invest more. Our model is used as a negotiation simulator to study the effects of such decisions not to invest in wind energy and how others may counter the situation.

The Netherlands is divided into 30 nodes that are connected by transmission lines. The considered time horizon is one year with hourly resolution. The input data includes, among others, the spatio-temporal variations of wind and solar capacity factors and their maximum potentials, which is obtained from [16]. Onshore wind turbines, solar PV, OCGT, hydrogen storage, and flow battery storage are considered technologies. Due to the differences in their efficiencies and cost parameters, hydrogen storage is best suited for long-term usage, whereas battery storage provides an option for short-term storage. Furthermore, in this national planning process, the regions are not asked to propose capacity in offshore wind, and thus offshore wind is not considered. Since quite a significant generation expansion is needed, the existing generation and storage capacities are not considered for the ease of presenting results. The existing transmission network is considered, and the capacity can be expanded. Direct current (DC) power flow calculations are performed based on the existing capacities. 2030 estimations for other techno-economic parameters are used and are taken from [46] except for the network cost and the hydrogen storage efficiency, which are taken from [16]. Note that fuel costs, particularly gas, are based on values before 2022. The techno-economic parameters used in this study are given in Table 1.

Although all the three indirect costs in (2) are of significance and interest in practice, in this case study, the focus is on the last item, which is related directly to the bilateral trading and show its effects on the results. This is because from the modeling perspective, the first two items, representing social costs and taxes/subsidies, indicate a direct change of cost parameters. Their effects resemble a global sensitivity study which is a common approach to analyze results in optimization-based studies and thus are not further investigated in this work. The ratio of traded energy between the pool market and the bilateral market Φ_n is important in practice, analyzing the effects of this parameter will add further complexity for understanding the model results. Therefore, the results for a full pool market representation (when $\Phi_n = 0$) and a full bilateral market representation (when $\Phi_n = 1$) with various values of the bilateral trading terms will be shown.

4. Results and discussions

This section presents results from the analysis for the Regional Energy Strategies, followed by discussions and reflections of the approach.

4.1. Optimal investment decisions for a full pool market representation and a full bilateral market representation

This subsection presents the optimal total installed capacities for the system. The pool market is first discussed. Then, the bilateral trades are analyzed where $E_{n,m}^{\text{bilateral-ic}}$ represent increasing transaction costs (TC), starting from 10% of the average electricity price to 30%, 50%, 70%, and 90% to investigate the influences of TC on the planning decisions. The interpretation of TC in this case study is two-fold. On the one hand, the TC could be considered as actual costs. On the other hand, they can be deemed as a cost proxy for willingness to pay, i.e., bilateral trading barriers due to various rationales such as geopolitical considerations.

From left to right in Fig. 1, the following observations are obtained. First, onshore wind capacity declines while solar and storage capacity increase. Second, hydrogen and battery storage play an equally important role, and both have a significant surge in capacity. Thirdly, the expansion of transmission network capacity is marginal for all the cases. To be more specific, onshore wind capacity needs to climb to around 35 GW. Even though offshore wind energy is not considered in this model, this indicates how much offshore wind capacity is needed. Given that the capacity factors for offshore wind turbines are generally higher than those of the onshore, the obtained result is more conservative than when offshore wind is considered. Moreover, to reach the emission goals, the needed capacity for solar PV ranges from 41 GW to 55 GW. Due to the increase in solar capacity, the system levelized cost of energy increases for each case, which are 88 €/MWh, 90 €/MWh, 93 €/MWh, 96 €/MWh, 97 €/MWh and 99 €/MWh, respectively.

Fig. 2 shows the optimal capacities over the country for the two markets, respectively. The planning decisions under full pool market representation (left figure) is first discussed. Cost-optimal results are obtained because no preferences are considered in the pool market. Wind capacity is mostly placed in coastal regions where the wind resources are good, i.e., northwestern borders. Compared to wind, the capacity factors of solar PV are more evenly spread over the country. The right figure shows the planning decisions under a full bilateral market representation with 10% TC. The results are significantly different from those in the left figure. Compared to the cost-optimal results, trading barriers are introduced by the use of TC, and thus the resulted capacities are more local, where they are in line with the energy demands of the regions.

4.2. Abandoning wind energy for a region

Land-use and social acceptance issues of wind energy make it difficult for regions to invest in wind energy in a complex energy system environment. The potential choice of bypassing wind energy investment creates extra costs for the system and the individual nodes. In this subsection, the benchmark situation is analyzed first where there are no preferences towards certain RES, i.e., opposition to wind energy is not considered. Next, the investment preferences against wind energy are considered. These two situations will be referred to as benchmark and scenario 1, respectively. For illustration purposes, only one region

Table 1
2030 estimation of techno-economic parameters. The potentials, the network costs, and the hydrogen storage efficiency are taken from [16]. The rest is taken from [46].

Technology	CapEx (€/kW)	FOM (€/kW/yr)	VOM (€/MWh)	Lifetime(yr)	Potential (GW)
Onshore wind	1182	35	0.015	25	58.23
Solar PV	600	25	0.01	25	379
OCGT	400	15	58.4	30	
Hydrogen conversion	555	9.2			
Hydrogen storage	8.4 €/kWh	62% (in/out efficiency)			
Flow battery conversion	310	9.3			
Flow battery storage	144.6 €/kWh	90% (in/out efficiency)			
Network	10 000 €/MW/km				

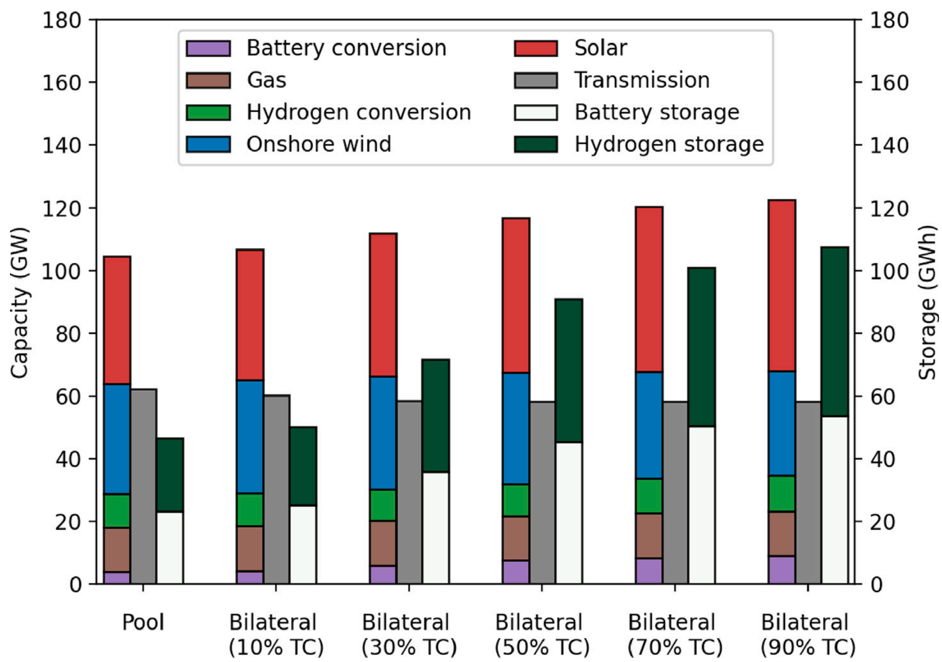

Fig. 1. Optimal total installed capacities for the Netherlands under a full pool market representation and a full bilateral market representation with different TC (% of the average electricity price).

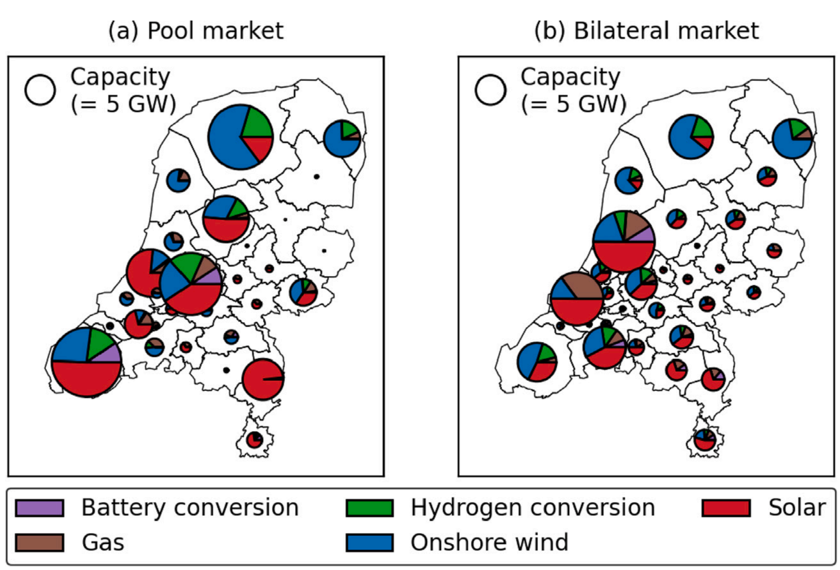

Fig. 2. Optimal installed capacities over the Netherlands. Left to right: full pool market representation, full bilateral market representation with 10% TC.

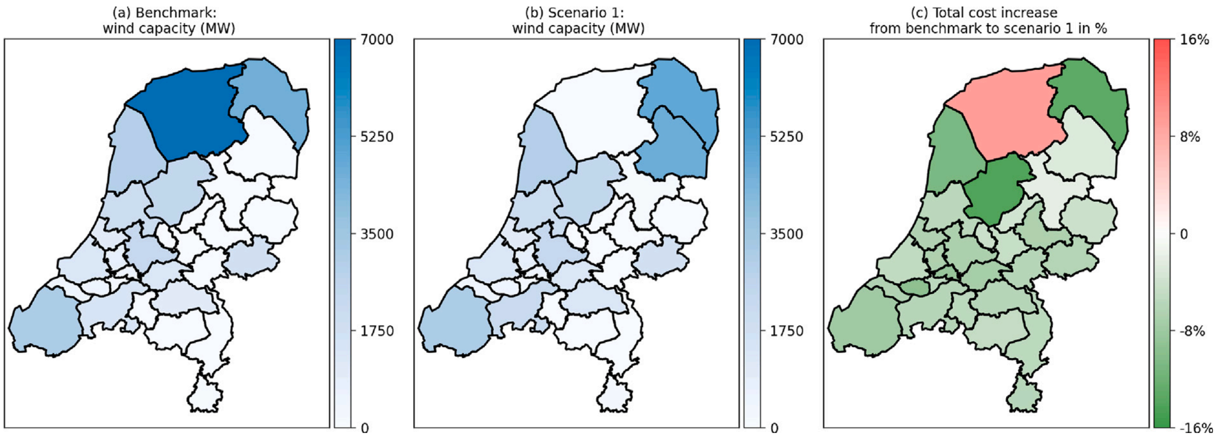

Fig. 3. Geographical distributions of wind energy capacity in benchmark and scenario 1, and net increase in total costs in %.

that acts against wind energy is considered, and the influences of this choice will be presented.

Fig. 3 depicts the wind capacity distribution for the benchmark situation. It shows a concentration in capacity in the coastal regions (later referred to as capacity centers), i.e., the country's northwestern border. Due to the discrepancy between demand centers and capacity centers, most of the energy produced in capacity centers will be transmitted to the demand centers in the west and the middle.

Among the capacity centers, the Friesland region (see the map in Fig. 4), sparsely populated and located in the north, is chosen as the focal region. There, energy demands are moderate (3% of the total energy demand), whereas the optimal wind capacity is the largest in the country (20% of the total wind capacity). For this reason, as a hypothetical case, it is assumed that this region proposes no investments in wind energy due to high social resistance. Other regions or other groups of regions may also be chosen, where the gist of this case study still applies.

Taking this preference into account, Fig. 3 also displays the new capacity distribution. Because of the decrease in wind capacity in Friesland, almost all other regions will have to build more generation capacities. In particular, the Drenthe region has to build 4680 MW more in wind energy.

In addition to capacity changes, the cost changes are analyzed, which are measured in percentages. In this case, the average costs for regions are calculated differently from the traditional cost of electricity. Traditionally, when calculating the cost of electricity, only the system-level costs as shown in the objective function of the ESOM are considered. However, here, the revenue/cost transfer between the regions are also considered. The revenues/costs come from selling and/or buying energy in the markets, where the prices are derived from the market balances (5)–(8). The motivation is that this study brings the market perspective into the ESOM, accordingly, the total costs include the revenues/costs in addition to the costs incurred from investing and operating the assets. The underlying assumption is that a region is an aggregation of local producers and consumers where the costs are also assumed to be local. The financing of the generation assets from outside the region is out of the scope of the current study. Our way of analyzing the cost indicates that the average costs for a region can be negative, provided that lots of revenues are gained from energy trading. The interpretation should be that the region (i.e., the producers and consumers as a whole) is benefited, but it does not necessarily mean that the electricity prices for the consumers are low. Friesland, as a result of fewer costs in wind energy investment yet more costs for importing energy, ends up with a total cost that is 16% higher. Although a few of its neighboring regions benefit by gaining more revenues from exporting energy, most regions incur more costs due to the large increases in investments. This demonstrates that the deliberate choice of one region influences the planning decisions of all other regions. More specifically, most regions suffer, though unwillingly, both in terms of increased total costs and forced wind energy investments locally.

This cost analysis is based on the pool-based electricity market. Under such a market, regions can bypass their wind energy investment and choose to import energy from other regions without binding penalties. As shown by the results, when wind turbines are placed at unfavorable locations in other regions, the cost of the system will increase, which will be borne by regions over the country. In this sense, as the hypothetical focal region in our case, Friesland is a free rider of the national RES investments, and other regions might do the same. As a result, the planning process stalls where no one commits to invest.

In practice, the planning process is far more complex than cost considerations. In this study, this problem is approached from the cost perspective and insights are provided. The following subsection will illustrate how our approach can act as a negotiation tool in such a collaborative planning process.

4.3. Other regions' negotiation strategies

With the help of external means, regional RES planning can be made by government mandate or facilitated by making favorable conditions so that regions have an interest. e.g., through the local sharing of profits [47]. Without considering the external means, the collaborative RES planning can be a negotiation process between the regions. When other regions are unwilling to comply with Friesland, which would be the case in our hypothetical example, their bilateral relationships deteriorate. This, in turn, affects Friesland as well. Here, our model is used to simulate the negotiations between the regions. This will be done by considering the indirect costs associated with the energy trades, which is used to represent the willingness to pay for the region. In this exemplary case, due to Friesland's choice, the willingness to pay for other regions concerning trades with Friesland becomes low. In other words, a high cost is imposed on the trades from other regions as their negotiation strategy to Friesland's proposal.

Fig. 5 shows the costs of Friesland in various scenarios. The benchmark is first discussed. Due to the large investment needs in wind energy, the fixed and variable costs (together referred to as investment costs) are high. However, since most generated energy will be transmitted and sold to other regions, Friesland will gain significant revenues from selling energy. Overall, its total net cost in the benchmark case is 393 M€. The benchmark case provides the least cost solution for this region. If preferences against wind energy are taken into account, its cost will increase. In that case, its investment costs decline to 14% of those in the benchmark case. Accordingly, due to the lack of local generation capacities, it has to import energy, with the net export percentage dropping from 230% to −50%.

Fig. 4. Map of the 30 regions in the Netherlands.

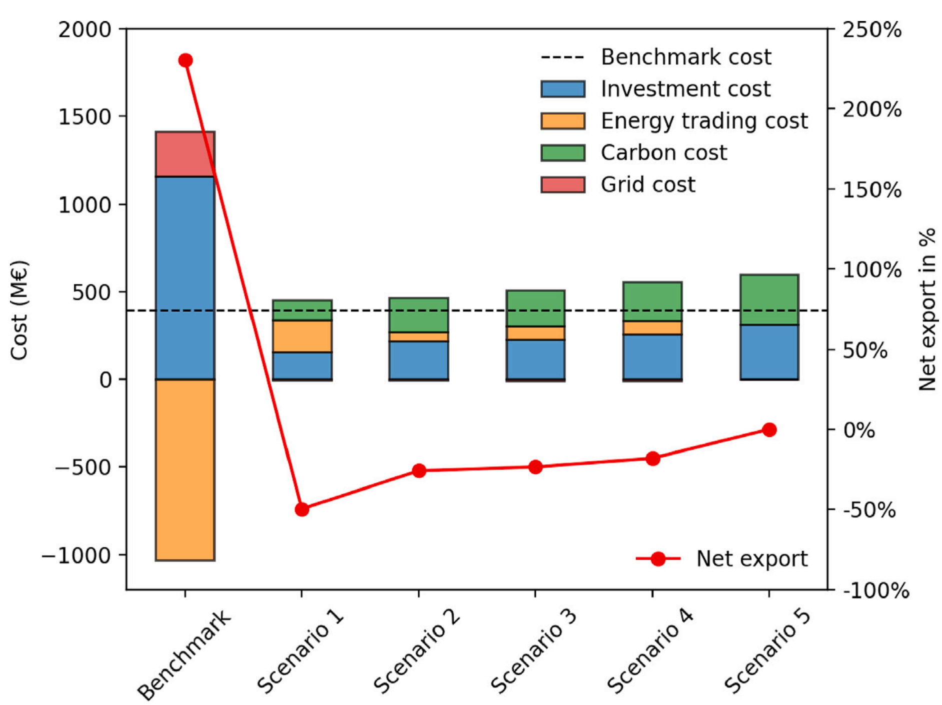

Fig. 5. Costs of Friesland in various scenarios.

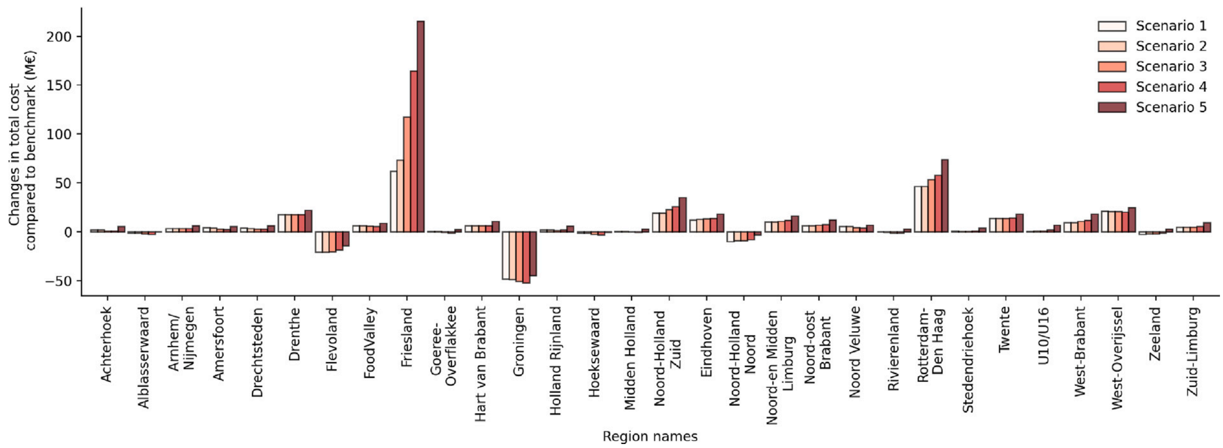

Fig. 6. Costs of all the regions compared to benchmark in scenario 1 to scenario 5.

Then, the results of the following scenarios (2–4) are analyzed when other regions start to negotiate with Friesland, with increasing levels of preference cost (10 €/MWh, 50 €/MWh, 100 €/MWh). These indicate degrees of the willingness to pay with trades that involve Friesland. The results show that as the trading barriers between other regions and Friesland become larger, the energy trades shrink, and thus, Friesland will be forced to rely more on its energy production, which drives up its total costs. In the extreme case (scenario 5), the region will be isolated by others and has no other choice but to be energy self-sufficient. All these scenarios are not desirable for Friesland, and therefore, it has to reconsider its decision not to invest in wind energy.

Now the cost changes for other regions are evaluated. A key question to answer here is, by imposing trade barriers with Friesland, what are the consequences for other regions? Fig. 6 shows the cost changes relative to the benchmark cost for five cases. There are mainly two groups of regions to be discussed. One group is Friesland's neighboring regions with similar wind conditions and low energy demands. Among all, Drenthe builds more wind capacity and incurs more costs than the benchmark. Flevoland and Groningen have fewer costs since they benefit from more energy sales. The other group consists of the load centers, Noord-Holland Zuid (Amsterdam region) and Rotterdam-Den Haag, which rely heavily on imports. Due to the choice of Friesland, the energy prices go up, leading to higher costs for the load centers as well. In particular, when Friesland does not invest in wind and others take no action, Rotterdam-Den Haag has a higher cost increase than Friesland. Nevertheless, Friesland bears the most cost increase in all other cases, especially when the counteraction is strong in negotiations.

4.4. Discussions

Because the key contribution of this work, i.e., incorporating indirect costs for energy system planning, has not been studied before, it is impossible to compare our results with other published work. Nevertheless, comparing the pool results (i.e., without modeling the indirect costs) with the results from the literature will provide insights while further enhancing the uniqueness of our model. A conventional ESOM was proposed by Wang et al. (2020) and the Dutch power system to achieve different RES targets was designed [16]. In our case, the system levelized cost of energy is 88 €/MWh, while [16] indicates around 80 €/MWh for the same RES share (71%). This is mostly because in [16], there is coal in the generation mix, which results in lower levelized cost. In our case, coal is not considered to comply with the government mandate to phase out coal. Our paper shows comparable results and even improves the results by reflecting policy evolvements in recent years.

The scope of this case study is chosen so that readers can correctly and clearly understand the key message that the case study conveys with just the right amount of information. First of all, the case gives practical insights into how the Dutch power system may be designed considering indirect costs, as already validated against other published work. Secondly, due to the long-term nature of the planning problem, various uncertainties exist, such as the changing economic conditions or the used values for the willingness to pay. However, uncertainty modeling is out of the scope of the current study. This is because this paper focuses on a generic topic (modeling indirect costs) that is usually discussed in different sets of literature. Accordingly, the case study presents a coherent but diverse set of results, i.e., the optimal investment capacities under ideal conditions, those under a hypothetical free-rider case, and the negotiation strategies thereof. Although uncertainty analysis is important, adding more analysis would lessen our key message. Nevertheless, uncertainty analysis would enhance the practical use of the case results, which leaves room for future studies in this direction. There is also room for future work regarding the willingness to pay because the topic of this case study is not to argue for the best values to quantify the willingness to pay but rather to show how the indirect costs can help express the region's preferences and simulate the inter-regional negotiation process. To this end, Friesland has been used as an illustrative region, but the discussion should be away from Friesland into more general inter-regional negotiations. Moreover, it is assumed that all regions have the same willingness to pay, and they all counter one particular region's choices. The exact values for willingness to pay depend on the bilateral relationships between other regions and the region under study, which can relate to economic aspects such as how much influence they perceive for their regions or socio-political factors such as the political tensions between them. Some regions may even benefit, as shown already. In addition, with various values for willingness to pay from the regions, they may again choose to change their perceptions depending on the results. Therefore, the actual results highly depend on the case-specific situation when the model is used in practice. Our case study highlights how this model can be used to investigate these kinds of policy-relevant challenges.

5. Conclusions

Energy system optimization models are known for their policy implications based on optimal long-term investment decisions. From a socio-technical perspective, their cost modeling focuses on the capital costs and operation & maintenance costs. However, the costs related to the social subsystem are often not modeled. This study presents a refined energy system optimization model that incorporates indirect costs.

Different indirect costs associated with generation capacity, energy production, and bilateral trades, respectively, are explicitly modeled. This model goes beyond the prevalent cost-minimization paradigm by incorporating these indirect costs. In this paper, those associated with bilateral trades are elaborated. Based on the interpretation, they could either be viewed as an improved utility function or account for exogenous costs. As such, transaction costs, trading barriers, and willingness to pay can be modeled.

The model is demonstrated using a proof-of-concept case study of the highly renewable Dutch power system in 2030. The first part of the case study focuses on using indirect cost terms to represent transaction costs. It has been found that, the inclusion of the transaction costs associated with bilateral trades changes the results when compared with the conventional cost-optimal energy system optimization models in different ways. In terms of the generation mix of the system, the capacity of wind energy drops while that of solar PV increases. The geographical distribution also changes. The cost-optimal results indicate that more generation capacities are placed at locations with favorable weather conditions. However, the resulting capacities become more local when bilateral trades are considered. The second part studies the situation where a group of regions has to decide on their investments to meet a joint carbon target where a potential free-rider problem occurs. The technology preferences of the regions are considered, in particular, an assumed unwillingness to invest in wind energy. The model acts as a negotiation simulator to inform the regions about the consequences of such a preference. Furthermore, the model can simulate the negotiation strategies to benefit the regions by using the indirect cost terms that represent willingness to pay.

The case study has demonstrated the capability of the proposed model to model transaction costs, trading barriers, and willingness to pay. The model can be used to model future energy systems under more realistic settings considering indirect costs and can simulate negotiations in a collaborative planning process.

CRediT authorship contribution statement

Ni Wang: Conceptualization, Methodology, Software, Data curation, Investigation, Visualization, Writing – original draft, Writing – review & editing. **Remco A. Verzijlbergh:** Conceptualization, Methodology, Supervision, Funding acquisition, Writing – review & editing. **Petra W. Heijnen:** Supervision, Funding acquisition. **Paulien M. Herder:** Supervision, Funding acquisition, Writing – review & editing.

Declaration of competing interest

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

Data availability

Data will be made available on request.

Acknowledgment

This research received funding from the Netherlands Organization for Scientific Research (NWO) [project number: 647.002.007].

References

[1] Fattahi A, Sijm J, Faaij A. A systemic approach to analyze integrated energy system modeling tools: A review of national models. Renew Sustain Energy Rev 2020;133. http://dx.doi.org/10.1016/j.rser.2020.110195.

[2] Pfenninger S, Hawkes A, Keirstead J. Energy systems modeling for twenty-first century energy challenges. Renew Sustain Energy Rev 2014;33:74–86. http://dx.doi.org/10.1016/j.rser.2014.02.003, URL: http://linkinghub.elsevier.com/retrieve/pii/S1364032114000872.

[3] Groissböck M. Are open source energy system optimization tools mature enough for serious use? Renew Sustain Energy Rev 2019;102. http://dx.doi.org/10.1016/j.rser.2018.11.020.

[4] Chang M, Lund H, Thellufsen JZ, Østergaard PA. Perspectives on purpose-driven coupling of energy system models. Energy 2023;265:126335. http://dx.doi.org/10.1016/j.energy.2022.126335.

[5] Deng X, Lv T. Power system planning with increasing variable renewable energy: A review of optimization models. J Clean Prod 2020;246. http://dx.doi.org/10.1016/j.jclepro.2019.118962.

[6] Lund H, Arler F, Østergaard PA, Hvelplund F, Connolly D, Mathiesen BV, Karnøe P. Simulation versus optimisation: Theoretical positions in energy system modelling. Energies 2017;10. http://dx.doi.org/10.3390/en10070840.

[7] Mostafaeipour A, Bidokhti A, Fakhrzad MB, Sadegheih A, Mehrjerdi YZ. A new model for the use of renewable electricity to reduce carbon dioxide emissions. Energy 2022;238. http://dx.doi.org/10.1016/j.energy.2021.121602.

[8] Wang N. Incorporating institutions into optimization-based energy system models. Delft University of Technology; 2022, http://dx.doi.org/10.4233/uuid:01a3ced0-59bb-484a-beeb-0bfbe4d904b8.

[9] Ferez-Arriaga IJ, Meseguer C. Wholesale marginal prices in competitive generation markets. IEEE Trans Power Syst 1997;12(2):710–7. http://dx.doi.org/10.1109/59.589661.

[10] European Commission. Quarterly report on European electricity markets, vol. 13. Technical report 4, 2021.

[11] Drechsler M, Ohl C, Meyerhoff J, Eichhorn M, Monsees J. Combining spatial modeling and choice experiments for the optimal spatial allocation of wind turbines. Energy Policy 2011;39. http://dx.doi.org/10.1016/j.enpol.2011.04.015.

[12] Drechsler M, Egerer J, Lange M, Masurowski F, Meyerhoff J, Oehlmann M. Efficient and equitable spatial allocation of renewable power plants at the country scale. Nat Energy 2017;2. http://dx.doi.org/10.1038/nenergy.2017.124.

[13] Shih YH, Shi NX, Tseng CH, Pan SY, Chiang PC. Socioeconomic costs of replacing nuclear power with fossil and renewable energy in Taiwan. Energy 2016;114. http://dx.doi.org/10.1016/j.energy.2016.07.118.

[14] Salomon H, Drechsler M, Reutter F. Minimum distances for wind turbines: A robustness analysis of policies for a sustainable wind power deployment. Energy Policy 2020;140. http://dx.doi.org/10.1016/j.enpol.2020.111431.

[15] Krumm A, Süsser D, Blechinger P. Modelling social aspects of the energy transition: What is the current representation of social factors in energy models? Energy 2022;239:121706. http://dx.doi.org/10.1016/j.energy.2021.121706.

[16] Wang N, Verzijlbergh RA, Heijnen PW, Herder PM. A spatially explicit planning approach for power systems with a high share of renewable energy sources. Appl Energy 2020;260:114233. http://dx.doi.org/10.1016/j.apenergy.2019.114233.

[17] Bartholdsen HK, Eidens A, Löffler K, Seehaus F, Wejda F, Burandt T, et al. Pathways for Germany's low-carbon energy transformation towards 2050. Energies 2019;14. http://dx.doi.org/10.3390/en12152988.

[18] McKenna R, Pfenninger S, Heinrichs H, Schmidt J, Staffell I, Bauer C, et al. High-resolution large-scale onshore wind energy assessments: A review of potential definitions, methodologies and future research needs. Renew Energy 2022;182. http://dx.doi.org/10.1016/j.renene.2021.10.027.

[19] Liu J, Lin Q, Huang G, Wu Q, Li H. Energy systems planning and GHG-emission control under uncertainty in the province of liaoning, China - a dynamic inexact energy systems optimization model. Int J Electr Power Energy Syst 2013;53:142–58. http://dx.doi.org/10.1016/j.ijepes.2013.04.013.

[20] Yazdanie M, Densing M, Wokaun A. Cost optimal urban energy systems planning in the context of national energy policies: A case study for the city of Basel. Energy Policy 2017;110:176–90. http://dx.doi.org/10.1016/j.enpol.2017.08.009.

[21] Quiroga D, Sauma E, Pozo D. Power system expansion planning under global and local emission mitigation policies. Appl Energy 2019;239:1250–64. http://dx.doi.org/10.1016/j.apenergy.2019.02.001.

[22] Li T, Li Z, Li W. Scenarios analysis on the cross-region integrating of renewable power based on a long-period cost-optimization power planning model. Renew Energy 2020;156:851–63.

[23] Zhen J, Huang G, Li W, Wu C, Wang S. Electric power system planning with renewable energy accommodation for supporting the sustainable development of Tangshan City, China. J Clean Prod 2016;139:1308–25.

[24] Yin JN, Huang GH, Xie YL, An YK. Carbon-subsidized inter-regional electric power system planning under cost-risk tradeoff and uncertainty: A case study of Inner Mongolia, China. Renew Sustain Energy Rev 2021;135.

[25] Hobbs BF. Linear complementarity models of nash-cournot competition in bilateral and POOLCO power markets. IEEE Trans Power Syst 2001;16(2). http://dx.doi.org/10.1109/59.918286.

[26] He Y, Wang L, Wang J. Cap-and-trade vs. carbon taxes: A quantitative comparison from a generation expansion planning perspective. Comput Ind Eng 2012;63(3):708–16. http://dx.doi.org/10.1016/j.cie.2011.10.005.

[27] El-Khattam W, Bhattacharya K, Hegazy Y, Salama M. Optimal investment planning for distributed generation in a competitive electricity market. IEEE Trans Power Syst 2004;19(3):1674–84. http://dx.doi.org/10.1109/TPWRS.2004.831699, URL: http://ieeexplore.ieee.org/lpdocs/epic03/wrapper.htm?arnumber=1318708.

[28] Karandikar RG, Khaparde SA, Kulkarni SV. Strategic evaluation of bilateral contract for electricity retailer in restructured power market. Int J Electr Power Energy Syst 2010;32(5):457–63. http://dx.doi.org/10.1016/j.ijepes.2009.09.018.

[29] Tang Y, Ling J, Wu C, Chen N, Liu X, Gao B. Game-theoretic optimization of bilateral contract transaction for generation companies and large consumers with incomplete information. Entropy 2017;19(6). http://dx.doi.org/10.3390/e19060272.

[30] Pourakbari-Kasmaei M, Asensio M, Lehtonen M, Contreras J. Trilateral planning model for integrated community energy systems and PV-based prosumers-A bilevel stochastic programming approach. IEEE Trans Power Syst 2020;35(1). http://dx.doi.org/10.1109/TPWRS.2019.2935840.

[31] Nazari AA, Keypour R. A two-stage stochastic model for energy storage planning in a microgrid incorporating bilateral contracts and demand response program. J Energy Storage 2019;21. http://dx.doi.org/10.1016/j.est.2018.12.002.

[32] Foley AM, Ó Gallachóir BP, Hur J, Baldick R, McKeogh EJ. A strategic review of electricity systems models. Energy 2010;35(12). http://dx.doi.org/10.1016/j.energy.2010.03.057.

[33] Imran K, Zhang J, Pal A, Khattak A, Ullah K, Baig SM. Bilateral negotiations for electricity market by adaptive agent-tracking strategy. Electr Power Syst Res 2020;186. http://dx.doi.org/10.1016/j.epsr.2020.106390.

[34] Wang N, Verzijlbergh R, Heijnen P, Herder P. Modeling the decentralized energy investment and operation in the prosumer era: a systematic review. In: 2020 IEEE PES innovative smart grid technologies Europe. IEEE; 2020, p. 1079–83. http://dx.doi.org/10.1109/ISGT-Europe47291.2020.9248838.

[35] Hahnel UJ, Herberz M, Pena-Bello A, Parra D, Brosch T. Becoming prosumer: Revealing trading preferences and decision-making strategies in peer-to-peer energy communities. Energy Policy 2020;137. http://dx.doi.org/10.1016/j.enpol.2019.111098.

[36] Sorin E, Bobo L, Pinson P, Member S. Consensus-based approach to peer-to-peer electricity markets with product differentiation. IEEE Trans Power Syst 2019;34(2):994–1004. http://dx.doi.org/10.1109/TPWRS.2018.2872880, arXiv:1804.03521.

[37] Morstyn T, McCulloch MD. Multiclass energy management for peer-to-peer energy trading driven by prosumer preferences. IEEE Trans Power Syst 2019;34(5):4005–14. http://dx.doi.org/10.1109/TPWRS.2018.2834472.

[38] Baroche T, Moret F, Pinson P. Prosumer markets: A unified formulation. In: 2019 IEEE Milan PowerTech. IEEE; 2019, p. 1–6. http://dx.doi.org/10.1109/PTC.2019.8810474.

[39] Baroche T, Pinson P, Latimier RLG, Ben Ahmed H. Exogenous cost allocation in peer-to-peer electricity markets. IEEE Trans Power Syst 2019;34(4):2553–64. http://dx.doi.org/10.1109/TPWRS.2019.2896654.

[40] Fodstad M, Crespo del Granado P, Hellemo L, Knudsen BR, Pisciella P, Silvast A, et al. Next frontiers in energy system modelling: A review on challenges and the state of the art. Renew Sustain Energy Rev 2022;160:112246. http://dx.doi.org/10.1016/j.rser.2022.112246.

[41] Hagspiel S, Jägemann C, Lindenberger D, Brown T, Cherevatskiy S, Tröster E. Cost-optimal power system extension under flow-based market coupling. Energy 2014;66:654–66. http://dx.doi.org/10.1016/j.energy.2014.01.025, URL: http://dx.doi.org/10.1016/j.energy.2014.01.025.

[42] Government of the Netherlands. National climate agreement. 2019, URL: https://www.government.nl/topics/climate-change/climate-policy.

[43] Unie van Waterschappen. Regionale Energie Strategie. 2019, URL: https://www.regionale-energiestrategie.nl/default.aspx.

[44] Netherlands Environmental Assessment Agency. Regionale Energie Strategieën; Een tussentijdse analyse. 2020, URL: https://www.pbl.nl/publicaties/regionale-energie-strategieen-een-tussentijdse-analyse.

[45] Unie van Waterschappen. RES 1.0 per regio. 2021, URL: https://www.regionale-energiestrategie.nl/bibliotheek/res++media/1643638.aspx?t=RES-10-per-regio.

[46] Schlachtberger DP, Brown T, Schramm S, Greiner M. The benefits of cooperation in a highly renewable European electricity network. Energy 2017;134:469–81. http://dx.doi.org/10.1016/j.energy.2017.06.004, arXiv:1704.05492.

[47] Hvelplund F, Möller B, Sperling K. Local ownership, smart energy systems and better wind power economy. Energy Strategy Rev 2013;1. http://dx.doi.org/10.1016/j.esr.2013.02.001.