REPORT

Injection charges for cross-border grid cost recovery

Producer network tariffs as a means of recovering grid investment costs from across the border: feasibility, implications, and design

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On behalf of TenneT TSO GmbH

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This study was carried out in collaboration between Neon and Consentec. Neon led the qualitative part, focusing on the role of injection charges as an instrument for cross-border cost recovery and their use as an incentive mechanism. Consentec was responsible for the modeling aspects and the case of the offshore grid cost allocation.

This study is available at neon.energy/injection-charges and consentec.de/publikationen

Neon Neue Energieökonomik is an energy economics consultancy based in Berlin. Since 2014, we have specialized as a boutique firm in sophisticated quantitative and economic-theoretical analyses of the electricity market. Through consulting projects, studies and training, we support decision-makers in addressing current challenges and future issues of energy system transformation. Our clients include governments, regulatory authorities, grid operators, energy providers, and electricity traders from Germany and across Europe.

Consentec has been providing expert advisory services to both public and private clients in the energy industry and energy technology sectors for 25 years. The company has focused on engineering, economic and regulatory issues related to energy supply, with a special focus on network planning and operation, security of supply, network and system integration of RES as well as market design and regulation. Consentec supports its clients through consultancy, technical and economic investigations, software solutions, training, and expert reports. Our clients are mainly ministries, regulatory authorities, network operators, energy suppliers, industry associations, IT providers and equipment manufacturers based in European countries.

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Summary

Background. In most European countries, the costs of building, maintaining and operating electricity grids are mostly recovered through network charges levied on local electricity consumers. By contrast, generators pay little or no network charges in most countries. However, substantial grid investment, increasing cross-border electricity flows, the expansion of wind and solar energy, and onset of large-scale battery deployment have led to debates on grid fee reforms. One of the most prominent proposals discussed in many European countries as well as in Brussels are injection charges: grid fees paid for producing electricity.

Many arguments. Injection charges, also known as producer tariffs, are suggested for a range of different reasons. Some point to the incentives they can provide, e.g. locational incentives in large pricing zones, or peak shaving incentives for solar generators. Others call for injection charges for distributional reasons, i.e. as a source of financing that allows reducing withdrawal charges. These arguments, however, sometimes seem to fail to account for the cost pass-through of costs to wholesale prices and hence confuse legal with economic incidence. Another argument is to recover costs from solar prosumers through injection charges. This study focuses on another, also distributional reasoning: using injection charges to recover domestic grid investment costs from foreign consumers.

Main topics. This study addresses this topic in two ways. First, we use economic theory applied to European coupled electricity markets to identify to what extent, under which conditions, and with what kind of side effects, injection charges lead to cross-border cost recovery. We identify the causal transmission mechanism: injection charges increase wholesale prices, leading to higher-priced exports, and hence make foreign consumers contribute to domestic grid costs. In this context, we also shed light on the economic incidence of injection charges within a country, e.g. to what extent they are passed on to domestic consumers via increased wholesale prices or to taxpayers through support schemes and capacity mechanisms. Second, we quantify the effects of recovering the network costs of offshore wind energy through an injection charge in the Netherlands and Germany. This is acutely policy relevant since the Netherlands have announced to introduce injection charges as an attempt to recover some of the large foreseen offshore grid connection costs.

Cost recovery. Our analysis clarifies that injection charges only contribute to cross-border cost recovery when two key conditions are met. First, the injection charge must lead to an increase in the wholesale price. Second, the country must be and remain (also after the introduction of the charge) an exporter of electricity. It is the higher-priced export of electricity that is the mechanism through which cross-border cost-recovery is achieved. This implies that the design of injection charges is crucial for meeting this objective: it needs to be small enough to avoid turning a net-exporting country into an importer to avoid becoming self-defeating, and it should be broad rather than limited to a subset of inframarginal generators, since then the wholesale prices impact will be limited. Also, the type of charge matters.

Energy vs. capacity charges. Like withdrawal charges, injection charges can come in the form of energy charges (per generated MWh) or capacity charges (per MW peak injection during a

period such as a year). While moderate energy charges might achieve some cross-border cost-recovery, we identify major issues with capacity charges: if they are not passed onto wholesale prices, they don't work for cross-border cost recovery. If they are priced in, it will likely be in the form of price spikes during a few hours, then probably turning the country into an importer. In either case, they will not lead to cross-border cost recovery. Price spikes might cause political backlash or, if suppressed, adequacy issues. In addition, price risk may increase, driving up capital costs, discouraging investments, and inflating the costs of renewable support schemes and capacity mechanisms. Overall, we caution against capacity injection charges.

European vs. unilateral. The economic effect of injection charges depends on who implements them: a common European energy injection charge would lead to little, if any, distortions. In contrast, if unilaterally introduced by one country, the injection charge will push production and possibly also investment to other countries, which is likely to reduce welfare. A unilateral injection charge has not only welfare effects, but also numerous distributional consequences. For example, it will tend to rise wholesale prices abroad, thereby redistributing wealth from consumers to producers in those countries.

Effect on industry. An additional aspect to be considered is that while most consumers in most countries are exposed to wholesale prices, often certain consumers are exempted from network charges. One example is electricity-intensive industry in Germany, representing about 20% of total consumption. These firms receive a rebate of up to 90% on grid fees. Injection charges raise wholesale prices while reducing withdrawal charges, which will be zero-sum for many, but for consumers who are mostly exempt from the withdrawal charges, this shift will lead to a net increase in costs.

Incentives. While the primary focus of this study is on international cost recovery, we also explore whether injection charges can provide desirable incentives for generators to compensate for market design shortcomings. For example, injection charges could substitute missing locational signals (if location-specific and time-variant), reduce peak injection of solar and wind generators, or help internalize export-related network costs. While well designed injection charges might be part of a solution to some of these problems, alternative instruments are likely to be more effective and targeted, e.g. splitting the bidding zone (locational incentive), reforming renewables support schemes (reduce generation peaks), or expanding market coupling (internalize network costs).

The case of offshore. Offshore wind farms come with large grid connection costs, due to both offshore and onshore grid investments as well as – in the case of hybrid parks – interconnectors to other bidding zones. In this study, we explore the possibility of recovering offshore grid connection costs through a selective injection charges levied on offshore wind, using an electricity market model. With a unilateral injection charge for offshore wind in either Germany or the Netherlands, these costs cannot be fully recovered, as they depress offshore generation. When designed as an energy charge, the charge is passed on directly to the consumers, raising consumer costs and lowering offshore market revenues. Moreover, the energy charge fails in collecting significant cost contributions from abroad. A selective connection charge on offshore wind on the other hand would likely either reduce investment or, if compensated by support payments, be ultimately borne by taxpayers.

1 Introduction

Context. In most European countries, electricity networks are predominantly financed by consumers through network usage charges paid when withdrawing electricity from the grid. Electricity producers, by contrast, do not pay for injecting energy into the grid. This approach, along with other elements of the network charge system, has remained largely unchanged since the liberalization of the electricity sector. Consequently, injection charges play only a minor or negligible role in most EU Member States. For example, Germany and the Netherlands do not impose such charges on electricity producers, while other countries apply them in the transmission or distribution grid only. Sweden is the sole country that recovers a substantial share of its transmission and distribution grid costs through injection charges (Figure 1). Moreover, EU Regulation 838/2010 caps transmission charges for generators at a modest level of 0.5 €/MWh, except for a few countries that had already implemented injection charges prior to the regulation. Additionally, certain costs are exempt from this cap, including the cost of grid connection, costs for ancillary services, and costs for grid losses.

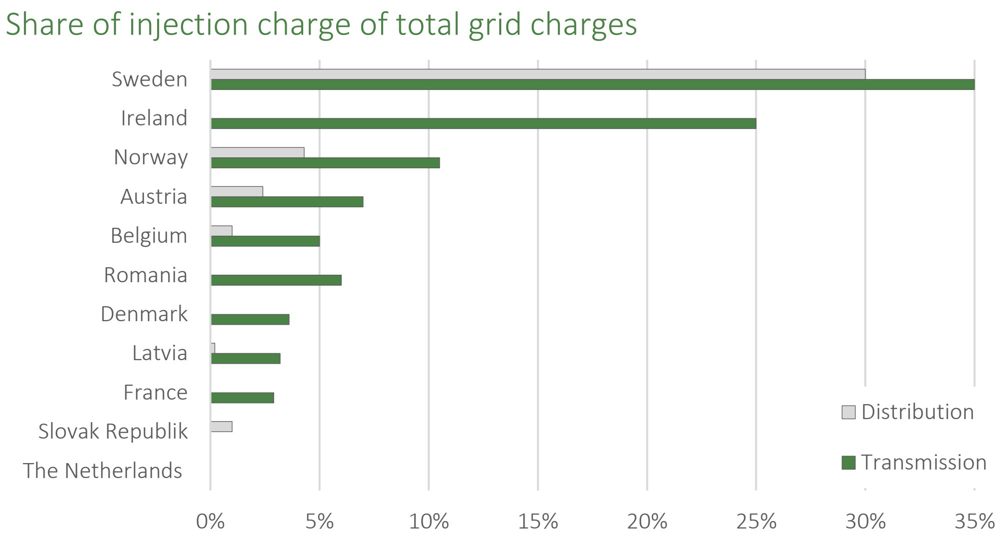


Figure 1. Share of injection charges of the total grid fee revenues. In the Netherlands, generators only pay a small lump sum fee, covering administrative costs, which is not considered as an injection charge by national law. Source: ACER Network Tariff Report (2023)

Timely. Historically, grid fees have attracted less academic and policy attention than other elements of electricity market design – such as wholesale pricing, capacity mechanisms, or renewable support schemes – making this an under-researched area with significant potential for reform. Nonetheless, sector experts and academics have debated whether electricity producers should also pay grid tariffs. Today, there are several independent reasons why the debate is gaining momentum:

- Rising grid costs: As electricity grids now account for a growing share of overall system costs, grid fees make up an increasing portion of consumers' bills. For instance, transmission network charges have recently doubled both in the Netherlands and in

Germany. For residential consumers in Germany, grid fees can be larger than the cost of energy.

- Limited European harmonization: While many aspects of the electricity system are coordinated across Europe, grid fees vary widely, raising concerns about cross-border distortions in an increasingly integrated market.
- Increasing cross-border flows: Deeper market integration has led to higher levels of cross-border electricity trades, with investments in one country increasingly affecting its neighboring countries. This is not only true for cross-border interconnectors, but for many network investments within country borders.
- Financing challenges: The lack of an effective structural cross-border financing mechanism – the cross-border cost-allocation and the inter-TSO compensation mechanism have not proven to fulfil this role sufficiently – may result in underinvestment, especially for offshore grid connections, as national grid operators and regulators focus (mainly) on domestic costs and benefits.
- Energy system changes: The system of network charges has barely changed in the past 20 years, despite significant shifts in the energy system and market dynamics, e.g. the rise of wind and solar energy, the arrival of batteries, and the looming electrification of the energy systems.
- Policy shifts: Recent moves by the Dutch regulator to introduce injection charges and by the German regulator to reform network fees create a window of opportunity for research and policy intervention.

Arguments for injection charges. Injection charges can serve multiple purposes in the electricity system. In general, their introduction can be justified based on two overarching goals: providing efficient signals or ensuring fair cost allocation.

Incentives. Injection charges can be designed to send locational and temporal signals that reflect network congestion. Then, they can be seen as an alternative to structural interventions like a bidding zone split. For example, battery-specific network tariffs could provide targeted locational incentives, encouraging system-friendly investments and operation of storage assets. Injection charges also provide incentives for peak shaving of generation. Injection charges can incentivize operators – especially solar plants– to reduce peak injections during times of network stress, such as midday periods in summer. This could reduce local network congestion.

Redistribution. Another possible objective of introducing injection charges is to redistribute grid costs more equitably among different parties.

- Producers vs. Consumers: A common argument, especially in Germany, is that producers also use of the network infrastructure and should therefore contribute to its financing. This argument challenges the traditional "load-pays" principle and seeks to align cost responsibilities more closely with actual network usage. However, the argument is flawed because most producers will simply pass on the additional costs through higher electricity prices, ultimately shifting the financial burden back to consumers.
- Consumers vs. Prosumers: As more consumers become prosumers (i.e., households that both consume and produce electricity) concerns arise that they are avoiding a

fair contribution to network costs. In this context, injection charges could ensure that such households also bear part of the financial responsibility for maintaining the grid they continue to rely on.

- Cross-border cost allocation: In the context of international electricity markets, injection charges are also discussed as a mechanism to involve foreign consumers in the financing of domestic grid infrastructure, particularly for offshore wind connections. The core argument is that domestic consumers often bear the full cost of infrastructure investments, even though neighboring countries also benefit significantly from increased transmission capacity and renewable generation. This aspect will be studied thoroughly in this study.

This study. This study focuses on the last aspect, the cross-border allocation of network costs. In particular, the study addresses a particularly acute policy issue: Are injection charges a sensible way to better allocate the cost of offshore wind connections? These costs are significant in size – they account for nearly half of the planned investments in the German transmission system – and are particularly complicated, if the offshore wind parks are directly connected to interconnectors (hybrid projects).

Structure. We study injection charge from two different perspectives. Chapter 2 focuses on cross-border cost recovery. It identifies the mechanisms and necessary conditions for recovering costs from foreign consumers, as well as possible consequences and drawbacks. We analyze the distributional and distortive effects of injection charges, viewing any deviation from market outcomes without these charges as a welfare-reducing distortion. Chapter 3 explores injection charges from a very different perspective. The actual electricity system faces many market-imperfections – such as the lack of locational signals. In this second-best context, network charges can be seen as a tool to address some of these imperfections and to provide desirable incentives for market participants. Chapter 4 provides specific reasoning and estimates for the case of Dutch and German offshore wind power. Chapter 5 concludes.

2 Cross-border cost recovery

In this chapter, we study the distributional effects and market distortions resulting from the introduction of injection charges. In particular, we identify conditions under which injection charges can be used for cross-border recovery of network costs. To structure our analysis of injection charges across different settings, we first define some key terms and establish an analytical framework.

2.1 Definitions and analytical framework

Terminology. There are different terms used to refer to grid fees paid by electricity producers, including “producer tariffs”, “generation component”, and “generation charge” (“G-charge”). In this study, we use the term “injection charge”, which is also used by ACER. This term includes any electricity injected into the grid (from generation and storage) and covers all types of tariffs, including connection and capacity charges.

Network. In this study, we use the term “network” shorthand for “network charge calculation region”, i.e. the area for which a network charge is calculated. According to this definition, a network may, but does not necessarily need to, coincide with a bidding zone or a balancing area. In Germany, for instance, each distribution system operator calculates its network charges individually and is hence one network. By contrast, the four transmission system operators calculate a joint network tariff and thus form one network together.

Closed vs. open. A closed network is one that does not exchange electricity with other networks (analogous to a “closed economy” in macroeconomics). An open network has electricity exchange with at least one other network, which we refer to as “import” and “export”, even if these flows occur within the same country.

Domestic vs. foreign. When we refer to a “domestic” network, we mean the one considering or introducing an injection charge. A “foreign” network is any other network that exchanges electricity with the domestic network.

Retail price. We refer to “retail price” as the sum of the wholesale electricity price and withdrawal charges paid by consumers. We do not differentiate between different types of consumers, i.e. connected to different voltage levels or consumers with grid fee rebates. We further assume dynamic pricing, i.e. quarter-hourly prices on wholesale and retail markets. Other retail components such as taxes and metering fees are disregarded in our analysis. We assume they are independent and exogenous to the system of network charges, so they should not affect our analysis nor distort findings.

Types of tariffs. In our study, we focus on three main types of injection charges:

- Energy charge: A charge levied on each MWh produced (€/MWh).

- Capacity charge: A charge levied on the individual peak injection (€/MW). For simplicity, we consider annual charges, i.e. levied per highest injection within a calendar year.
- Connection charge: A one-off charge at the time of grid connection, which only depends on the connection capacity (€/MW).

Unless specified otherwise, we assume the charges to have neither temporal nor spatial variation. We do not consider tariffs that are levied at time of peak system load, such as the British "triads".

Framework. We structure our analysis of injection charges along three main cases. First, we study the effects on an injection charge in a closed network, where no electricity is exchanged with other networks. Second, we apply a uniform injection charge across multiple networks, e.g. a common European injection charge. The comparison of these two cases allows us to isolate cross-border effects of injection charges from purely domestic effects. In the third case, we assess a unilateral charge that is introduced in only one out of several interconnected networks, e.g. one European country. In each case, we examine both energy-based and capacity-based injection charges, focusing on their distributional impacts and market distortions. Throughout this chapter, any deviation from market outcomes in the absence of these charges is treated as a welfare-reducing distortion.

Further assumptions. To focus on the fundamental effects of injection charges, we make the following simplifying assumptions:

- Perfect competition: The electricity market is assumed to be perfectly competitive, with no market power held by any participant
- Price-inelastic demand: Consumers' demand for electricity does not respond to price changes
- Redistribution of injection charge revenue: Any additional income generated from the injection charge is fully used to reduce the withdrawal charge
- Uniform charges: All consumers pay the same withdrawal charges, and all producers pay the same injection charges
- No storage: The model does not account for energy storage

In section 2.5, we relax these assumptions to explore more realistic scenarios and the robustness of findings.

2.2 Case 1: Closed network (no imports / exports)

We first assess injection charges in a closed network without import and export of electricity. Since there is no cross-border exchange, changes in network charges only affect domestic producers and consumers. Obviously, an injection charge cannot be used for cross-border cost recovery in a closed network. For illustration, we show examples for specific values: an energy charge of 5 €/MWh and a capacity charge of 22,000 €/MW (resulting in roughly the same payment for a generator operating at 50% capacity factor).

2.2.1 Energy charge

Merit order. An energy-based injection charge acts as an additional variable cost for generators, which they include in their spot market bids. If applied to all generators in a closed network, the wholesale price increases exactly by the amount of energy charge during all hours. Because the charge increases the variable costs of all generators, it does not affect the dispatch of generators (Figure 2). We assume that the revenue from this charge is used to reduce the withdrawal charge. Since in this case we study a closed network without imports and exports, generation equals consumption. Thus, money recovered through the injection charge allows to reduce the withdrawal charge by exactly the same amount. As a result, a 5 €/MWh injection charge leads to an increase in wholesale prices by 5 €/MWh and a decline in withdrawal charges by 5 €/MWh. Consequently, plant dispatch, retail price and the contribution margins of generators do not change.

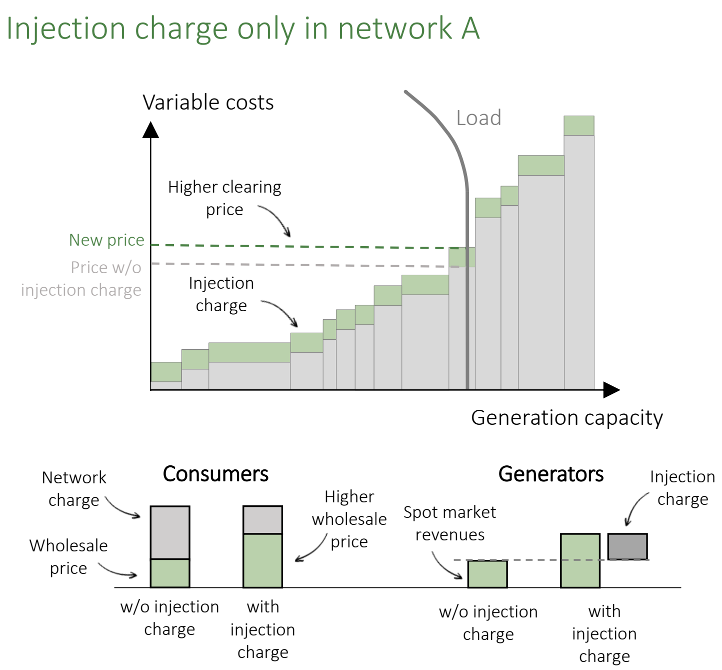
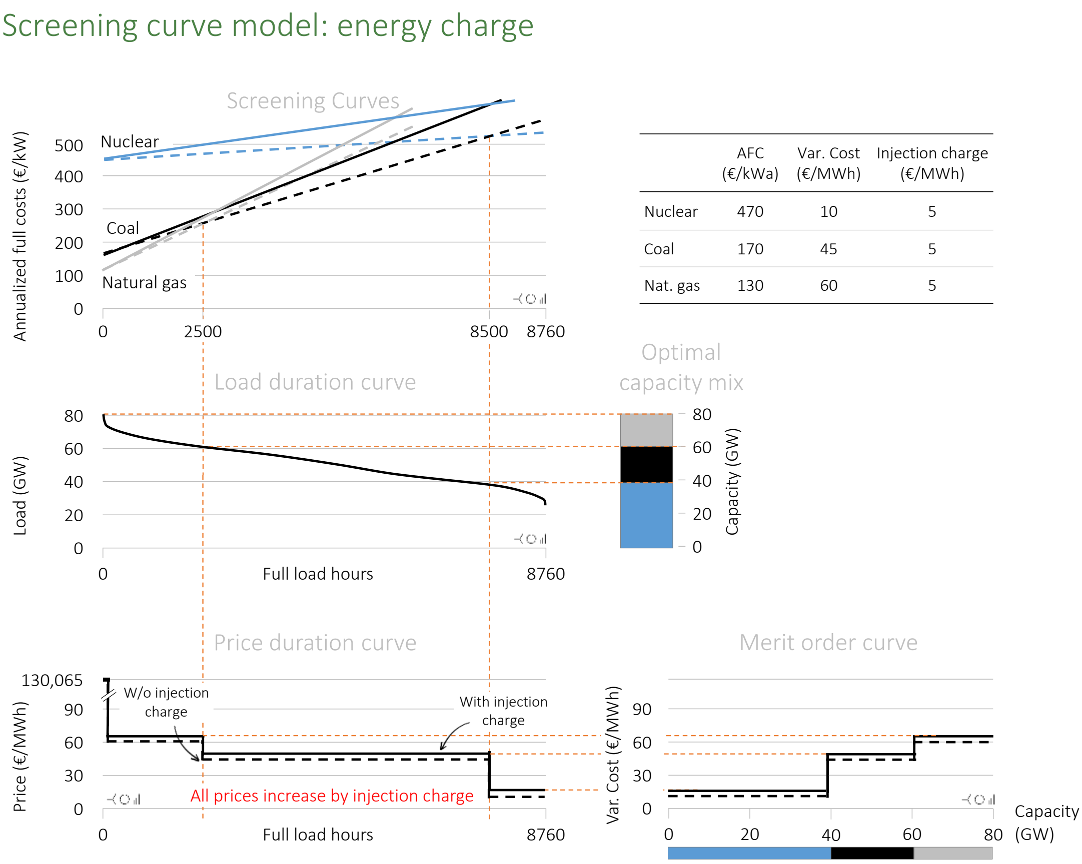


Figure 2. Injection charges in a closed network

Investments. The impact of an energy injection charge on investments can be studied with the screening curve model. This model determines the optimal dispatchable capacity and generation mix as a function of fixed and variable costs generation technologies. The model shows that a uniform energy charge does not affect the optimal capacity mix. This is because all generation technologies face the same increase in variable costs, their relative competitiveness remains unchanged. This result holds also when including wind and solar energy in the set of available technologies, even if this more complex case cannot be illustrated in the screening curve model.



	AFC (€/kWa)	Var. Cost (€/MWh)	Injection charge (€/MWh)
Nuclear	470	10	5
Coal	170	45	5
Nat. gas	130	60	5

Figure 3. Screening curve model: energy charge in a closed network

Effects. In essence, (partly) replacing a withdrawal charge with an injection charge leads to no meaningful outcome in a closed network. Generators pass on the injection charge and hence the wholesale price increases, but a corresponding decline in the withdrawal charge leads to an unchanged retail price. As a result, neither the generation mix nor dispatch is affected, and no welfare gains or losses occur. Since there is no cross-border trade in a closed network, network costs cannot be shifted elsewhere, making injection and withdrawal charges effectively equivalent.

2.2.2 Capacity charge

Mechanism. A capacity injection charge has a similar effect as an (annualized) investment cost: by paying a one-time fee or a periodic fee per megawatt of the individual peak capacity, generators effectively "buy" the right to use that capacity over a defined period. Well-established cost metrics from power plant economics – such as screening curves and the levelized costs of electricity are two metrics that can be adapted to examine how generators bear these charges.

Dispatch logic. Under an energy charge, the decision-making process is straightforward: in each market time unit, generators produce as long as the wholesale price exceeds their marginal cost, which now includes the additional energy charge. By contrast, a capacity charge requires a more forward-looking perspective. When considering increasing their peak injection, generators must evaluate whether the extra cost of the injection charge will be offset by higher profits over all remaining market time units for that period (e.g., for the rest of the year). In practice, this decision will need to be taken under uncertainty, increasing the challenge and the risks of taking this decision.

Scarcity prices. Generators that are subject to a capacity-based injection charge factor these additional annualized fixed costs into their market bids. In a theoretical scenario with perfect foresight and completely inelastic demand, a generator facing a capacity charge of 22,000 €/MW per year must recover this cost in the one quarter hour, when the generator is needed to satisfy electricity demand (scarcity pricing). In practical terms, this could result in a quarter-hour price spike of around 88,000 €/MWh. This situation is shown in Figure 4. Under more realistic conditions, where demand is elastic and/or foresight imperfect, or if the charges are levied on a monthly basis, cost recovery is likely to occur through multiple slightly lower price spikes rather than during a single event.

Wholesale price impact of injection charge

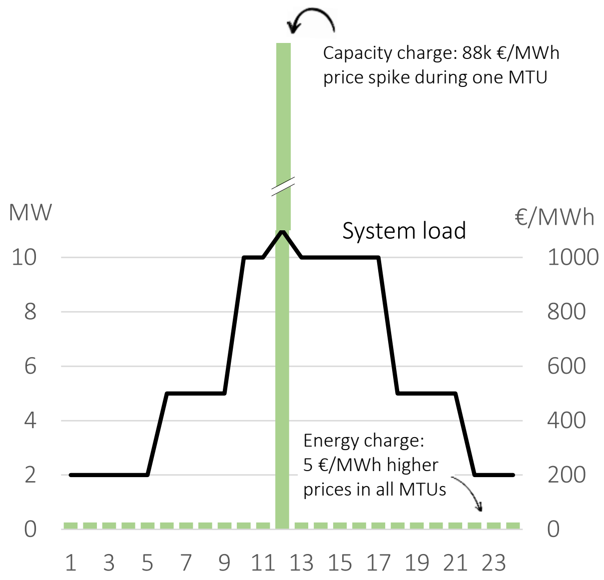
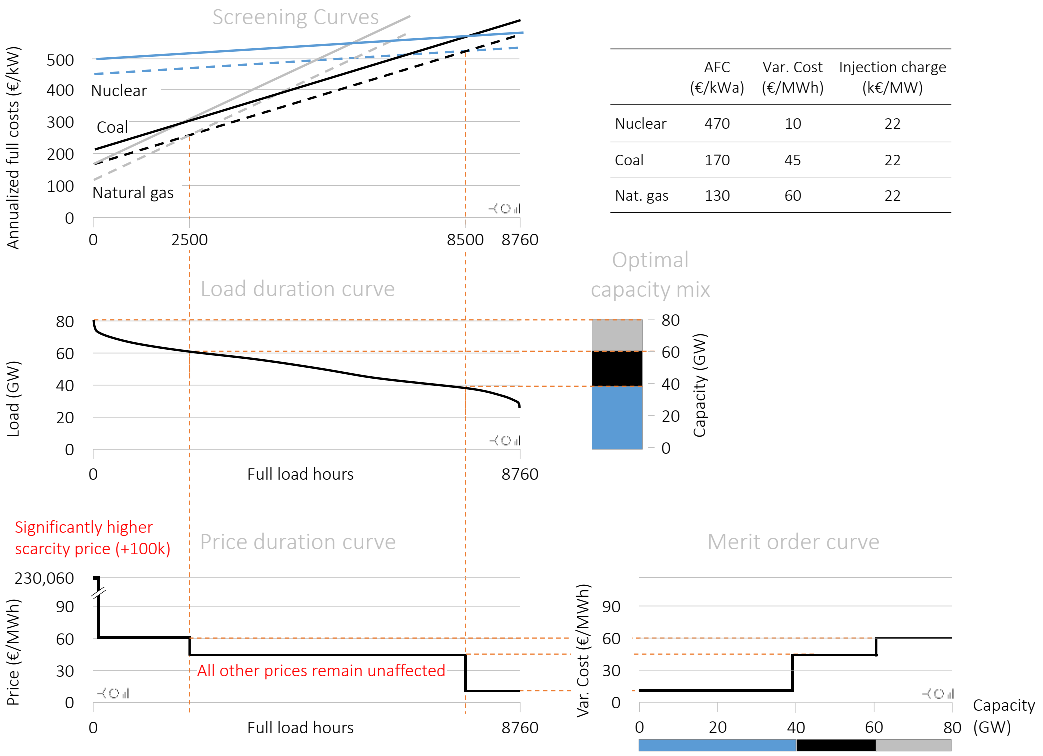


Figure 4. Influence of capacity charges on the wholesale price in a closed network

Example. To illustrate this, consider the rational behavior of a peaking gas plant in mid-December during a scarcity situation, e.g. the one on December 17, 2024 in Germany. Suppose this plant has not been operating earlier in the year, so that when it decides to produce electricity, it faces the full annual capacity charge. As the year comes to an end and the likelihood of further operation diminishes, especially with the Christmas season approaching, the plant may only run for one quarter hour. Consequently, the operator must determine a wholesale price at which production becomes economically viable. In other words, the generator must secure a price high enough to cover not only its fuel, CO_2, and start-up costs, but also the entire capacity charge. In this example, that threshold would be above 88,000 €/MWh for that quarter-hour. At a price below this level, the generator would be unable to recover its costs and would then not generate electricity. This shows the threat of politically undesired scarcity prices. In addition, the example reveals that a capacity charge can even challenge security of supply, as the power plant may decide not to operate at the moment of scarcity if it cannot factor the injection charge into its bids.

Screening curve. The screening curve model indicates that the introduction of a capacity charge has no impact on the optimal capacity mix or merit order. The capacity charge does not alter the relative competitiveness of different generators, as it is effectively treated as a fixed cost. However, what does emerge is a significant scarcity price. Crucially, these scarcity prices do not provide an efficient price signal for incentivizing new investments. Instead, they artificially exacerbate scarcity situations, as the capacity charge itself creates additional financial risk for generators.

Screening curve model: capacity charge



	AFC (€/kWa)	Var. Cost (€/MWh)	Injection charge (k€/MW)
Nuclear	470	10	22
Coal	170	45	22
Nat. gas	130	60	22

Figure 5. Screening curve model: capacity charge in a closed network

Renewables. The scarcity price emerges during the (one) market time unit with the highest electricity consumption. Because the injection charge is based on the individual peak generation, generators whose peaks occur at different market time unit than the system peak, cannot pass on the full charge. For dispatchable generators, this is less problematic because they typically operate at full capacity during the system peak, ensuring that individual and system peaks align. However, for wind and solar, this misalignment is significant: these generators often do not produce at nameplate capacity during system peaks, and therefore, they cannot fully recover the injection charge through wholesale revenues. In the long run, this could reduce their market share and even lead to second-order price effects, such as inflated wholesale prices. Consequently, although a capacity charge does not distort the thermal generation mix, it depresses the revenue for wind and solar generators and thereby makes them less competitive.

Capped generation. A capacity-based injection charge is likely to lead to a strategic curtailment of renewable assets. By curtailing peak generation, renewable assets may save more from a lower injection charge compared to what they lose from selling less electricity. This holds especially for solar, which rarely generates at peak capacity and because wholesale prices are often relatively low during periods of peak solar output. For illustration, we analyzed the optimal dispatch behavior of a 1 MW solar plant in central Germany during 2023 that is exposed to a capacity-based injection charge. The results show that reducing peak generation by 21% – equivalent to curtailing approximately 33% of the nameplate capacity (around 670 kW) – maximizes the plant's net revenues (Figure 6). This incentive for curtailment reduces the share of renewable generation in the power mix but can ease stress on distribution and transmission networks.

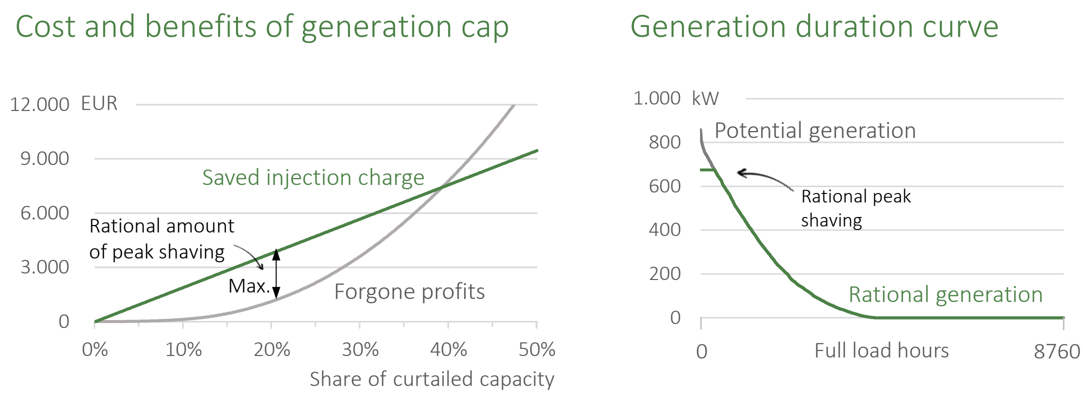


Figure 6. Incentives for solar plants to cap production

Drawbacks. A capacity-based injection charge introduces additional uncertainty for generators, making bidding decisions more complex and riskier. In a closed network, generators would incorporate the capacity charge into their bids to recover its full cost. Under more flexible assumptions, such as price-elastic demand, cross-border imports and exports, or greater uncertainty, it remains unclear whether generators can fully recover the capacity injection charge through their market revenues. This introduces a financial and operational risk that can influence long-term investment decisions.

Conclusion. In a closed network with no exports, injection charges cannot recover grid costs from abroad. Since there is no cross-border electricity trade, any rise in wholesale prices affects only the domestic market. When the injection charge is energy-based, it functions similarly to a withdrawal charge: whether consumers pay a higher withdrawal charge or a higher wholesale price with a lower withdrawal charge makes no substantial difference to retail prices, dispatch, investments, welfare, or cost distribution. However, this is not the case with capacity charges. These can create pronounced scarcity prices during system peak market time unit. These charges create an incentive for generators, especially renewable ones, to cap their production to reduce the capacity charge, leading to a shift in the capacity mix that favors dispatchable technologies and introduces an anti-renewable bias. This bias is problematic because it increases financial risks for generators, raises capital costs, and undermines market stability, ultimately hindering the transition to cleaner energy sources.

2.3 Case 2: Common (European) injection charge

In this section, we examine the case when the injection charge is introduced across interconnected networks, like a European-wide injection charge. To this end, we consider two networks: Network A and Network B. The networks are in two separate bidding zones and there is electricity exchange between them. We assume that the same injection charge is implemented in both networks. Again, we study two types of injection charges: an energy charge of 5 €/MWh and a capacity charge of 22,000 €/MW p.a., based on individual peak injection capacity.

2.3.1 Energy charge

Spot markets. If both networks charge an injection charge of 5 €/MWh, every generator in both networks incurs an additional variable cost of 5 €/MWh, which raises the wholesale price by 5 €/MWh in both markets.

XB-Trade. A uniformly applied injection charge that is fully incorporated in all generator bids does not change the dispatch of generators and hence does not alter the interconnector usage. Consequently, neither market distortions nor welfare losses occur. The additional revenues from the injection charge can be used to reduce the withdrawal charge. In the exporting network, local generation exceeds local consumption. The withdrawal charge can therefore be reduced by more than the increase in the injection charge, effectively benefiting consumers in that network (Table 1). Vice versa, the retail price for consumers in the importing network increases.

Table 1: Consequences of a common energy-based injection charge of 5 €/MWh in interconnected networks

	Exporting network	Importing network
Wholesale price	up 5 €/MWh	up 5 €/MWh
Producer profit	unchanged	
Withdrawal charge	down > 5 €/MWh	down < 5 €/MWh
Retail price	down	up
Plant dispatch	unchanged	
Welfare	unchanged	

Example. Figure 7 illustrates this for two interconnected networks. Network A is a net exporting network with 2 GWh generation and 1 GWh electricity consumption. Network B is a net importer: it has a domestic generation of 9 GWh and a local consumption of 10 GWh. When both networks introduce a common injection charge, wholesale prices increase by 5 €/MWh in all hours. In Network A, the injection charge amounts to 10 000 EUR (2 GWh x 5 €/MWh), allowing it to reduce the withdrawal charge by 10 €/MWh (10 000 EUR / 1 GWh). As a result, the overall retail price paid by consumers in Network A declines by 5 €/MWh. Conversely, Network B collects 45 000 EUR from injection charges (9 GWh x 5 €/MWh) but this only allows reducing the withdrawal charge by 4.5 €/MWh (45 000 EUR / 10 GWh). This leads to an increase in the retail price by 0.5 €/MWh in Network B.

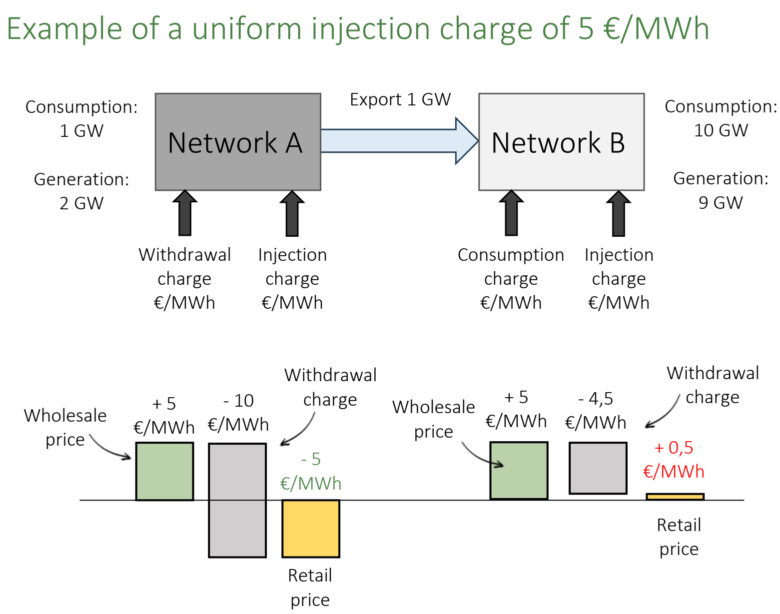


Figure 7. Redistribution of costs through a common injection charge

Cost recovery. In this scenario, the energy charge partially recovers grid costs that occur in Network A from Network B.

2.3.2 Capacity charge

Mechanism. The price mechanism for a capacity-based injection charge in two interconnected networks follows the same logic as in a closed network: the capacity charge triggers scarcity prices and incentivizes wind and solar generators to cap their production peaks.

Distributional effects. The distributional effects of these scarcity prices depend on whether the networks are in the same bidding zone (e.g., DSOs) or in two separate zones (e.g., TSOs in different countries). If both networks are in the same bidding zone, the scarcity price occurs at the same moment. The distributional effects then only depend on the flow of electricity in the scarcity hour. For the same reason as for the energy charge, consumers in the exporting network benefit from the injection charge, and consumers in the importing network lose. By contrast, scarcity prices can occur at different moments when the networks are in different bidding zones. In that case, both networks are most likely importing electricity in their own scarcity hour, hence each country's injection disadvantages the local consumers. Thus, a capacity-based injection charge will most likely not reallocate network costs to consumers in other networks.

2.4 CASE 3: UNILATERAL (NATIONAL) INJECTION CHARGE

Setup. Finally, we examine a scenario in which an injection charge is introduced in one network but not in the neighboring networks. This corresponds to a national injection charge. For illustration, we consider the case of two networks, but the results can be generalized. Network A implements the injection charge, and we call this domestic network. Network B does not introduce an injection charge. Both networks are interconnected but in separate bidding zones.

Mechanism. A unilateral injection charge affects cost allocation and market outcomes through three main channels: wholesale prices, TSO income through network charges, and congestion income. A common injection charge resulted in a uniform price increase in both networks and thus did not affect interconnector usage and congestion rent. With a unilateral injection charge, the situation becomes more complex.

Outcome. The effects of a unilateral injection charge depend on several key factors:

- Export status: In a net exporting network, the revenue base for collecting the injection charge is larger than for the withdrawal charge. Thus, the additional revenues can reduce withdrawal charges by more than the injection charge. The opposite holds for a net importing network.
- Can cross-border flows change: If the interconnector between the two networks is unconstrained, price changes in one network also affect the wholesale price in the neighboring network. For example, an increase in wholesale prices in an exporting network is (at least partially) transmitted to the importing network. However, if the interconnector is congested, prices between networks diverge and the wholesale price increase remains confined to the network that introduced the injection charge. In such cases, any change in wholesale price levels affects congestion rents of the interconnector.
- Where is the price-setting plant: The effect of the injection charge also depends on the location of the price-setting power plant. If the price-setting plant is in the network with the injection charge, the wholesale price increases. Conversely, if the price-setting plant is in the network without injection charge, the wholesale price remains unchanged.

2.4.1 Energy charge

Example. An energy-based injection charge can have very different effects from hour to hour. We start with the example of an hour where network A exports electricity, the interconnector is uncongested, and the price-setting generator is in A. This setup is illustrated in Figure 8. A small energy-based injection charge that does not change any of these characteristics results in an increase in the spot price by the amount of the injection charge in both networks. As above, consumers in the exporting Network A benefit from a higher reduction in withdrawal charges than the increase in the spot price. Meanwhile, consumers in Network B face higher retail prices. In addition, generators in Network B enjoy windfall profits because their variable costs remain unchanged while they receive a higher market price.

Injection charge of 5 €/MWh only in Network A

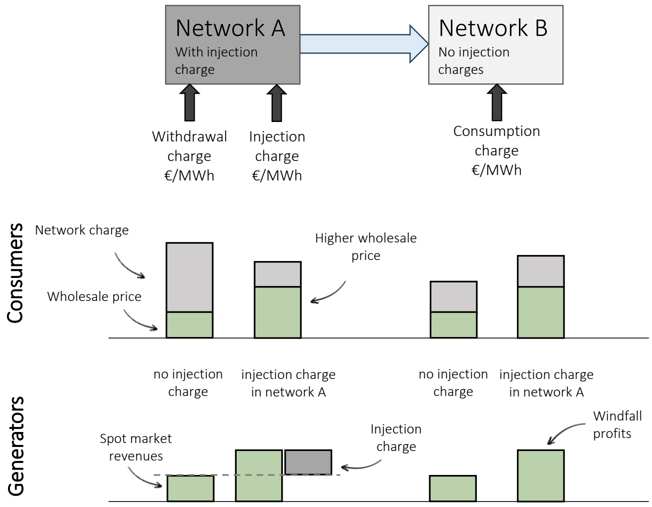


Figure 8. The effect of an energy-based injection charge only in Network A in one exemplary hour

Further outcome. This example represents just one of six possible cases. To explore the spectrum of outcomes, we consider two scenarios in detail:

- Scenario 1: Network A produces more electricity than it consumes (consumption: 1 GW, generation: 2 GW), exporting half of its generation to Network B, which has higher levels of both consumption (10 GW) and generation (9 GW). Any congestion income on the interconnector is split equally, at 50:50.
- Scenario 2: Network A is importing half of its total consumption (consumption: 2 GW, generation: 1 GW), drawing power from Network B, which has a higher consumption (10 GW) and generation (11 GW). Congestion income is likewise shared equally.

Six cases. Within each scenario, outcomes vary based on whether the interconnector is at its limit and where the price-setting generator is located. For each of the two scenarios, three combinations of interconnector status and location of the price setting generator are possible:

- The power flow between the networks can change (because the interconnector is not at its limit, or the two networks are within the same bidding zone), and the price-setting generator is subject to the injection charge
- The power flow between the networks can change, and the price-setting generator is *not* subject to the injection charge
- The power flow between the networks cannot change (because the interconnector is already at its limit), and the price-setting generator is subject to the injection charge

The fourth theoretical case is not possible: when the interconnector is congested, each network has one price-setting plant. The price-setting plant in network A is therefore always subject to the injection charge. Table 2 summarizes all possible outcomes of the two scenarios and the effects on how the injection charge alters interconnector usage, wholesale prices, congestion income, and ultimately, the distribution of costs across both networks.

Changing situation. Import/export status, interconnector usage and location of the marginal generator can change from hour to hour, hence the effects of the injection charge can change from hour to hour too. In addition, the injection charge itself can change these factors.

Table 2: Six possible outcomes of a unilateral energy charge

		Scenario 1 Network A: generation = 2 x consumption Network B: higher generation and consumption			Scenario 2 Network A: consumption = 2 x generation Network B: higher generation and consumption		
Network A is …		… exporting			… importing		
Can power flow between networks change?		Yes (interconnector not limited / same bidding zone)		No (interconnector at limit)	Yes (interconnector not limited / same bidding zone)		No (intercon-nector at limit)
Does the price-setting plant pay injection charge?		Yes (in A)	No (in B)	Yes (in A)	Yes (in A)	No (in B)	Yes (in A)
Injection charge	Spread	unchanged (zero)	unchanged (zero)	- 5 €/MWh	unchanged (zero)	unchanged (zero)	+ 5 €/MWh
	Congestion income	unchanged (zero)	unchanged (zero)	- 5 €/MWh	unchanged (zero)	unchanged (zero)	+ 5 €/MWh
Network A (injection charge)	Wholesale price	+ 5 €/MWh	unchanged	+ 5 €/MWh	+ 5 €/MWh	unchanged	+ 5 €/MWh
	Producer profit	unchanged	- 5 €/MWh	unchanged	unchanged	- 5 €/MWh	unchanged
	Withdrawal charge	- 10 €/MWh	- 10 €/MWh	- 7,5 €/MWh	- 2,5 €/MWh	- 2,5 €/MWh	- 3,75 €/MWh
	Retail price	- 5 €/MWh	- 10 €/MWh	- 2,5 €/MWh	+ 2,5 €/MWh	- 2,5 €/MWh	+ 1,25 €/MWh
Network B (no inj. charge)	Wholesale price	+ 5 €/MWh	unchanged	unchanged	+ 5 €/MWh	unchanged	unchanged
	Producer profit	+ 5 €/MWh	unchanged	unchanged	+ 5 €/MWh	unchanged	unchanged
	Withdrawal charge	unchanged	unchanged	+ 0,25 €/MWh	unchanged	unchanged	- 0,25 €/MWh
	Retail price	+ 5 €/MWh	unchanged	+ 0,25 €/MWh	+ 5 €/MWh	unchanged	- 0,25 €/MWh

Domestic consumers. The analysis of the six possible cases highlights that consumers only benefit from the introduction of an injection charge if their network exports electricity. If generation in the domestic network sets the price, costs are shifted to consumers abroad, otherwise costs are borne by local generators that cannot pass on the injection charge to the wholesale price. However, if a network is sometimes importing electricity, a unilateral injection charge may also increase the retail price for domestic consumers.

Congestion income. The congestion income of interconnectors can decline because the injection charge captures a larger share of what would otherwise be split between the TSOs involved. Overall, this interplay demonstrates that the effects of a unilateral energy-based injection charge can be mixed and sometimes negative, occasionally producing outcomes contrary to what was originally intended.

Market distortions. Unilateral injection charges often cause a re-distribution in the neighboring network: producers in the neighboring network can only benefit from the unilateral injection charge due to rising wholesale prices, while consumers in the neighboring network tend to lose. This redistribution can be much larger than the intended cross-border reallocation of costs. Consider the example of an hour during which Network A exports 1 GWh of electricity to the neighboring network, with no constraint on the interconnector (Figure 9).

When the price-setting generator is in A, a 5 €/MWh injection charge in A raises the wholesale price in both networks by that amount. Although consumers in Network B collectively pay an additional 250,000 € for electricity during this hour, only 5,000 € of that sum flows from Network A to Network B. The remaining 245,000 € become windfall profit for producers in B, whose variable costs remain unchanged while they benefit from the higher market price.

Welfare losses. When a country imposes an energy-based injection charge unilaterally, a welfare loss may arise from the re-shuffling of generation. Cheap generators in the network with the injection charge might be replaced by more costly generators in the network without injection charge. This is inefficient and increases the cost of power supply in both countries.

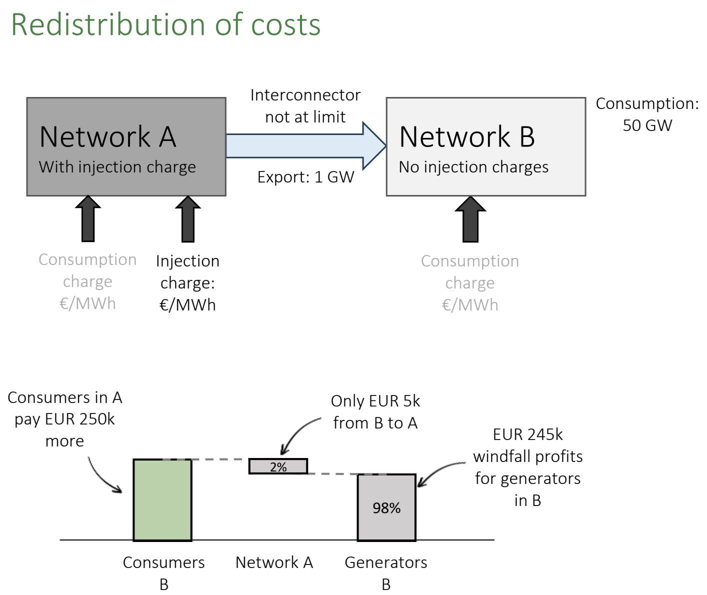


Figure 9. Re-distributional effects of an injection charge in the neighboring network

2.4.2 Capacity charge

Mechanism. A unilateral capacity injection charge operates under the same mechanism as in a closed network or in case with common (European) charges. In the setting of on unilateral charge, capacity charges trigger scarcity prices and create distortive incentives for renewables. Wind and solar generators, in response, tend to cap their production to reduce the charge paid, leading to an optimal capacity mix that shifts away from renewables and toward more dispatchable generators.

Cost recovery. A unilaterally applied capacity-based injection charge causes price spikes only in the domestic network. During these peak moments, the domestic network is almost certainly an importer, operating at full interconnector capacity (Table 3). As a result, the unilateral capacity injection charge does reallocate network costs to other networks: only domestic consumers bear the burden of higher prices.

Table 3: Unilateral capacity charge – only hour with scarcity price matters

	Network A is …	… exporting (generation = 2 x consumption)					… importing
	Can power flow between networks change?	Yes (interconnector not limited / same bidding zone)		No (interconnector at limit)	Yes (interconnector not limited / same bidding zone)		No (intercon-nector at limit)
	Does the price-setting plant pay injection charge?	Yes (in A)	No (in B)	Yes (in A)	Yes (in A)	No (in B)	Yes (in A)
IC	Congestion income	n/a	n/a	down 5 €/MWh	n/a	n/a	up 88k €/MWh
Network A	Producer profit	unchanged	down 5 €/MWh	unchanged	unchanged	down 5 €/MWh	unchanged
	Consumer rent	up	up > 5 €/MWh	up	down < 5 €/MWh	up < 5 €/MWh	down < 88k €/MWh
Network B	Producer profit	up 5 €/MWh	unchanged	unchanged	up 5 €/MWh	unchanged	unchanged
	Consumer rent	down 5 €/MWh	unchanged	down	down 5 €/MWh	unchanged	up

2.5 MODEL EXTENSIONS

The previous analysis is based on a set of strong assumptions. In this section, we relax assumptions such as the price-elastic demand, imperfect competition and consider additional cases.

2.5.1 Price-elastic demand

Effects. So far, we have assumed a price-inelastic electricity demand. However, if consumers adjust their electricity consumption in response to price changes, several additional complexities arise. Network charges that increase or decrease prices for consumers can influence consumption patterns in ways that may undermine economic efficiency, potentially becoming a potential source of welfare loss. In addition, they can lead to a reallocation of generation or consumption across borders.

Welfare effects. It is not straightforward to determine whether a reshuffling of generation or consumption across border improve or reduce welfare. The impact depends on how welfare-optimal the status quo is. Consider the example of injection charges that reduce the deployment of offshore wind energy in a particular country compared to the status quo. This could improve welfare if the amount of offshore wind energy in that country was too high, e.g. due to insufficient internalization of network costs. But this could also reduce welfare, if the initial amount of offshore wind energy in that country was already optimal or even below the optimal level. Unfortunately, identifying the welfare-optimal electricity power mix is challenging. Moreover, further questions arise around whether grid fee exemptions for certain consumers are inherently distortive or if they serve broader policy objectives, such as supporting energy-intensive industries.

2.5.2 Imperfect competition

Uncompetitive markets. When we relax the assumption of perfect competition, the injection charge may not translate into an equivalent change in the wholesale price. With market power, both a larger and a lower effect is conceivable. However, such an analysis is beyond the scope of this study.

2.5.3 Withdrawal charge exemptions

Setup. Not all consumers pay the same network charges. The impact of changes in transmission network charges on the retail price can vary significantly, because consumers are connected at different voltage levels or to different DSOs. Additionally, certain consumers, such as energy-intensive industries (e.g., those under §19(2) StromNEV in Germany), storages, or electrolysis plants, are exempt from grid fees in many countries. Moreover, some grid costs are recovered through levies that only apply to specific consumer groups, such as the offshore grid levy or the §19 levy in Germany.

Net effects. Injection charges impact the final consumer bill in two ways: they increase wholesale prices and reduce withdrawal charges. The combined effect depends, among others, on whether the consumer is subject to withdrawal charges. Consumers who pay network charges benefit from the reduction, while those exempt from withdrawal charges do not benefit from any offset. The latter may effectively lose due to higher wholesale prices. This effect is illustrated in Figure 10. Typically, exempted consumers are among the more price-sensitive or politically influential groups, such as energy-intensive industries. These distributional effects are additional to the cross-border and producer-consumer dynamics observed in Cases 2 and 3, highlighting the importance of considering the heterogeneity of consumer groups when evaluating the overall impact of injection charges.

Effects on different consumers in open networks

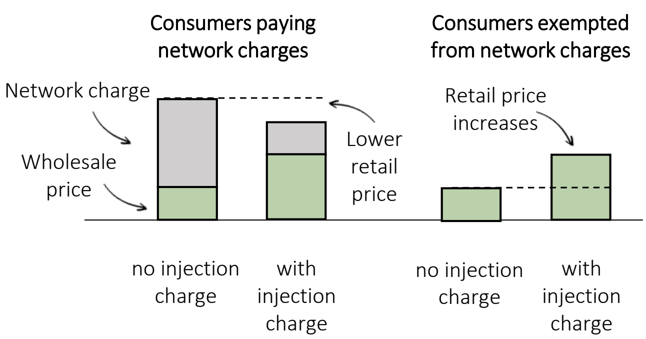


Figure 10. Net effects of injection charges on consumers exempted from network charges

2.5.4 Selective injection charges

Setup. Injection charges could, in principle, be applied selectively to certain types of generation – such as renewable energy plants only. However, this targeted approach introduces an extra layer of market distortion. By imposing higher costs on specific generators, it risks displacing lower-cost resources with more expensive ones, ultimately reducing overall efficiency. Even in a closed-network setting, this selective application can lead to welfare losses.

Example of offshore. For instance, consider an energy-based injection charge that applies solely to offshore wind. If the charge is high enough, offshore wind generation would be curtailed before thermal plants, despite its inherently lower costs. Even a modest charge could see offshore wind curtailed prior to onshore wind or solar generation, potentially exacerbating grid congestion – especially in low-voltage networks that already have significant solar and wind capacity. A more detailed analysis of these effects is provided in chapter 4.

2.5.5 Connection and contractual capacity charges (ex-ante charges)

Theory. Alternatives to an annual ex-post metered capacity charge are a one-off connection charge (€/kW) and an annual or monthly ex-ante contractual capacity charge (€/kW). While these methods differ in their timing and setup, they are identical in the long-term equilibrium with a perfect foresight. In the Screening Curve Model, both approaches effectively increase annualized fixed costs by the same amount per kilowatt. As a result, both types of charge lead to scarcity prices, produce an unchanged dispatchable capacity mix, and create the same downward bias against wind and solar generation.

Practice. Although a one-off connection charge or an annual ex-ante contractual capacity charge are similar to an ex-post metered capacity charge in the long-run equilibrium, they are quite different without perfect foresight. Under an ex-post metered capacity charge, the cost becomes relevant only when a generator decides to produce. At that moment, the unit must factor in the charge as an additional cost – effectively ensuring it sets a sufficiently high bid to recover the capacity charge if it operates only a handful of times (e.g., a peaking plant during a late-year demand spike). By contrast, connection and contractual capacity charges are paid upfront or at the start of a contract period, rendering them into sunk costs when dispatch decisions are made. Scarcity prices are still required to justify this initial investment, but the exact price-setting mechanism by which those prices emerge is less direct. Once the charge is paid, it no longer affects the generator's marginal cost, which can result in less transparent and predictable scarcity pricing compared to an ex-post metered approach.

Cost recovery. When it comes to ex-ante contractual capacity charges (or connection charges), it is less certain whether they would generate the kind of scarcity prices seen with ex-post metered charges. Regardless, if the aim is to recover grid costs from abroad, the cost transfer mechanism relies on increased wholesale prices during export hours. In practice, if scarcity prices do emerge, the network is almost certain to be importing in those hours – meaning no foreign consumers would bear the cost. Conversely, if scarcity prices do not occur, there is no wholesale price increase to pass on. In either situation, no portion of the grid costs would be recovered from outside the domestic network.

2.5.6 Investment support schemes

Investment mechanism. When an injection charge cannot be factored into wholesale electricity prices, purely commercial generation projects may become economically unviable. However, most forthcoming generation investments will be backed by public support schemes or capacity mechanisms. These policy instruments often involve fixed targets e.g. for capacity expansion; thus, they will compensate for a potential shortfall induced by an injection charge. As a result, introducing an injection charge does not necessarily change the overall volume or mix of new generation, since government-backed programs will still aim to meet their targets. Instead, the cost burden shifts to taxpayers or public funds. Essentially, the revenue from injection charges is redirected back into support schemes or capacity mechanisms to fill the funding gap they create. In practical terms, an injection charge such as connection charge for a new offshore wind farm would simply be built into the bids for Contracts for Difference, effectively passing the cost from developers to public finances. This redistribution merely shifts money between different public pots without altering the long-term investment decisions in the energy sector.

3 Network charges as incentives

New perspective. In the previous section, we considered any deviation from the original market outcome (without injection charges) as a welfare-reducing distortion and discussed injection charges as a mechanism to recover grid costs from abroad. This is, however, not the only reason for implementing such charges. In this section, we explore an alternative argument: viewing injection charges as a tool for providing desirable incentives for market participants, or in economic terms – a tool to internalize external costs.

Incentives for generators. If network charges are meant to provide incentives, one needs injection charges to expose generators to such incentives. For instance, if the aim is to relieve grid congestion during peak periods or encourage generation where capacity is most needed, it makes sense to apply these incentives to both consumers and producers, since both sides contribute to congestion and investment requirements. In other words, if network charges are meant to provide incentives, they should target generation as well as demand.

From problem to solution. Injection charges can influence the behavior of generators in various ways. To evaluate injection charges as an incentive mechanism, one should be precise in naming the problem that grid fees are meant to address. One (out of several) possible issue are the lacking locational incentives within bidding zones (for generators and consumers). This is an externality because the uniform wholesale prices do not reflect these internal network constraints. The first-best solution for this problem would be locational marginal pricing, which would signal the true cost of electricity at each substation by reflecting network constraints in the wholesale price. However, implementing locational marginal pricing seems currently infeasible due to technical, regulatory, and political constraints. Therefore, location-specific network charges as a proxy for locational prices might be a second-best solution.

A solution in search of a problem. Rather than starting with an instrument, in our case injection charges, and asking what problems it might solve, one should begin with the externality and work towards finding the most effective solution for addressing it. While injection charges may help address issues like excess electricity generation or grid congestion, they are just one of many possible solutions – and often other measures may prove more effective or less distortionary. It is beyond the scope of this study to rigorously assess externalities in electricity markets and evaluate first-best and second-best remedies, but some considerations can be sketched out for illustrative purposes.

Three externalities. In the following, we investigate three potential externalities that might potentially be addressed through injection charges:

- Network charges as locational incentives within bidding zones, substituting (missing) locational wholesale prices
- Injection charges can reduce peak network load by smoothing generation or capping peak injection
- The internalization of network costs of exports in case of incomplete flow-based market coupling

3.1 Locational prices

Externality. One key question is whether network charges can and should provide locational incentives within a network. The answer to this question largely depends on the design of the power market and the extent to which locational signals already arise from wholesale market prices or other policy instruments. Only if these signals are absent or insufficient, a role for network charges emerges to fill this gap.

Nodal pricing. There are various approaches to solve this defined problem. In a theoretical, first-best world, each connection point should have its own marginal price that reflects generation costs and grid constraints. If we assume perfect and complete markets – no transaction costs, no market power, no lumpy investments – and a long-term equilibrium for both generation and network investments, generators recover exactly their investment costs through these nodal prices, and grid operators earn back their costs from locational price spreads. Because each substation faces its own price, this system naturally provides optimal locational incentives for both generation and load.

First-best network charge. In practice, many European electricity markets use uniform zonal prices, which lack the spatial granularity of nodal pricing. These uniform prices do not reflect internal network congestion, and grid fees can be designed to replicate the missing locational signals. This charge would vary by node and time approximating the difference between the hypothetical nodal price and the zonal market price. In high-demand, import-constrained regions, grid fees may be positive (loads pay, generators receive). In high-generation, export-constrained regions, they may be negative (generators pay, loads receive). Any user injecting or withdrawing 1 kWh faces the same magnitude of charge, with opposite signs for generation and load. These first-best network charges would effectively replicate the nodal prices. Under these conditions, the net revenue from grid fees exactly covers grid costs, mirroring the first-best nodal solution.

Second-best network charge. In reality, grid fee design is constrained by limited granularity (spatial and temporal), imperfect information, and the strong preference to determine network charges ex-ante. The challenge is to approximate the first-best outcome within these constraints. In general, grid fee variation should mirror first-best fees: it should be higher in import-constrained regions – particularly during time of binding constraints. If one follows this line of thinking, one could justify the introduction of injection charges. However, this would also call for a fundamental reform of withdrawal charges for the same reasons.

3.2 Peak generation

Problem. A further question is whether network charges can effectively lower system costs by reducing peak injection – particularly from solar generators. As discussed in Section 2.2.2, a capacity-based injection charge could, in principle, create an incentive for producers to cap their generation, which might help ease strain on distribution grids. This is welfare-improving if all generation peaks impose network costs.

Source of the problem. However, before implementing such a measure, it is crucial to identify the underlying issue that one tries to address. Is the issue primarily non-responsive small-scale solar plants, a general supply-demand imbalance at the bidding zone level, or localized network congestion? If the main challenge is balancing supply and demand at the zonal level, then the wholesale price should already provide sufficient incentives for generators to limit production. If transaction costs or support schemes are the real source of price-unresponsiveness, these policies should be addressed directly. Moreover, capping generation only addresses locational constraints: if one generator curtails its production while demand remains constant and price-inelastic, another generator will simply take its place. Another possible concern is excess electricity at the system or national level, which can lead to non-market clearing situations. Two key issues emerge here: many solar generators, operating under feed-in tariffs, are not exposed to spot prices, and even those wind and solar plants that are exposed do not always adjust their output in response to low or negative prices.

Injection charges as solution. Thus, while injection charges might theoretically encourage generation curtailment, a capacity injection charge comes with severe side-effects as discussed in Section 2. It is thus most likely more efficient to address the root cause directly rather than relying on desired side effects of injection charges. For example, small-scale rooftop plants typically lack the equipment or incentives to respond to real-time price signals, suggesting that dynamic tariffs or phasing out feed-in tariffs could be more appropriate solutions. For large-scale plants, negative prices provide a clear signal to curtail production during oversupply, yet still not all operators respond adequately.

3.3 Grid costs of exports

Problem. A unilateral injection charge can cause a shift of new generation investment to other countries. In Section 2, we considered this effect a welfare-reducing distortion, as cheaper domestic generation is replaced by more costly foreign alternatives. However, if the grid costs of exports are not adequately internalized in investment decisions, this could also improve welfare.

Perfect market coupling. When all relevant network constraints are reflected in flow-based market coupling, prices between bidding zones diverge if any element is constrained. Under optimal network investment, these price divergences align with marginal network costs, leaving no externality to be addressed by an injection charge. For the case of offshore wind power, this would imply considering the offshore grid connection as a critical network element in the market coupling algorithm, and undersize the grid connection relative to the wind park nameplate capacity.

Imperfect market coupling. In reality, the market coupling algorithm only considers a limited set of network elements. Consequently, shifting generation and investment abroad via a unilateral injection charge could, in principle, raise overall welfare by reducing unaccounted-for grid costs.

Policy targets and support schemes. Even if pushing generation abroad appears to be more cost-effective (for instance, building onshore wind in one country instead of offshore wind in another), policy targets and support schemes often dictate renewable deployment. If these targets remain in place, a unilateral injection charge may not meaningfully alter the investment landscape, as support mechanisms effectively counteract any cost signals introduced by the charge.

4 Case of offshore grid cost allocation

In this chapter we analyze the quantitative effects of introducing a selective and unilateral injection charge by examining the case of offshore grid costs. First, we qualitatively discuss the effects on energy markets, dispatch and support schemes, as well as the distributive effects of a selective, unilateral injection charge on offshore wind. Second, we estimate the size of injection charges to refinance the offshore grid costs in Germany and the Netherlands, respectively. Finally, we conduct a model-based analysis of the effects of a unilateral energy injection charge on offshore wind on wholesale prices, offshore generation, market revenues, consumer costs and exchange patterns.

4.1 Allocating grid connection costs of offshore projects

The case of offshore. Offshore wind farms cause significant grid connection costs, due to necessary grid expansions both in the offshore and onshore grid as well as – in the case of hybrid assets – interconnectors with other bidding zones. The grid connection costs for offshore wind are thus significantly higher than for all other generation types. In Germany, the national grid development plan foresees around 160 bn € investment costs for the connection of offshore windfarms until 2045 (BNetzA, 2023). In the Netherlands, 35.5 bn € of investment cost in offshore grids are foreseen for platforms currently included in the national offshore wind development framework with a total capacity of 21 GW to be installed by 2032 (Ministerie van Economische Zaken en Klimaat, 2023).

Means to finance offshore connection costs. There are different means to finance offshore connection costs: In Germany and the Netherlands, consumers are charged a levy that is added to their consumption price. Germany additionally uses income from tendering offshore sites, the so-called “secondary bid component”, where offshore project developers pay in order to be awarded the right to develop their projects at the tendered offshore sites. A third option to finance offshore connection costs is to have offshore investors bear those costs, as is currently the case in Denmark and the UK. Finally, the option of financing offshore grid costs via an injection charge is examined within this study.

Offshore as a pilot technology for injection charges. To estimate the magnitude of an injection charge on offshore wind, a selective, unilateral injection charge applied exclusively to offshore wind farms is calculated, assuming full coverage of the offshore related grid costs by injection charges. The charge is applied either in Germany (DE) or the Netherlands (NL). The following table summarizes the installed capacity[1] and generation[2] of offshore wind, the total network cost[3] for offshore wind and the respective annualized network cost[4] assumed for Germany and the Netherlands for the year 2030. Based on these inputs, three different kinds of charges are calculated:

- An energy injection charge (€/MWh), assuming the total offshore grid costs are paid by domestic offshore wind producers in either Germany or the Netherlands according to their dispatched energy volumes.
- A connection injection charge (Mio. €/GW), assuming the total offshore grid costs are paid by domestic offshore wind producers in either Germany or the Netherlands according to their installed capacities.
- An energy consumption charge (€/MWh), assuming the total offshore grid costs are paid by domestic consumers in the ultrahigh voltage grid in either Germany or the Netherlands according to their energy consumption.

A capacity injection charge, on the other hand, is not considered for the case of offshore, as it has been shown to generate undesirable incentives and uncertainty (see chapter 2).

[1] The installed offshore capacities for Germany mirror the offshore goals according to the Offshore Wind Energy Act 2023, for the Netherlands the 2030 values were provided by TenneT (Ministerie van Economische Zaken en Klimaat, 2023).

[2] Generation was calculated assuming constant full-load hours. Note that this is a rather optimistic estimate, as with increasing wind installations and resulting wake effects, full-load hours of offshore wind are expected to decrease in the future.

[3] The total offshore network costs for Germany are taken from the project costs in Langfristszenarien (Consentec et al. 2024), those for the Netherlands from Ministerie van Economische Zaken en Klimaat (2023).

[4] Network costs are annualized over a lifetime of 30 years and with a WACC of 5.8 % in Germany (BNetzA, 2024) and a WACC of 6.4 % in the Netherlands (TenneT Nederland, 2024). The value for Germany corresponds to the replacement value of the network materials (including WACC), while the value for the Netherlands it includes all network costs (incl. depreciation, WACC, repairs, grid losses, general overhead, etc.).

Table 4: Inputs and results for models of allocating grid connection costs of offshore projects, based on purely exogenous assumptions

2030	DE	NL
Installed capacity (GW)	30,0	21,0
Generation (TWh)	91,1	80,21
Annualized Network Cost (Mio. €)	3.538,24	3.600,00
Total Network Cost (Mio. €)	35.638,60	35.500,00
Allocation options:		
Injection charge in a closed network		
1. Energy charge (€/MWh)	38,83	44,88
2. Connection charge (Mio. €/GW)	1.187,95	1.690,48
Consumption charge ultrahigh voltage in a closed network		
3. Energy charge (€/MWh)	12,29	45,81

Results. The resulting energy injection charge amounts to around 39 €/MWh for DE and 45 €/MWh for NL, a connection charge amounts to 1.2 bn €/GW for DE and 1.7 bn €/GW for NL, reflecting the lower amounts of offshore wind capacity and generation foreseen in NL in 2030 compared to DE. An energy consumption charge yields even more strongly diverging figures, as the energy consumption on the ultrahigh voltage grid is expected to be significantly larger in DE (290 TWh) than in NL (15 TWh)[5]. This calculation does not account for potential effects on the market equilibrium or injection volumes. In order to analyze such effects, a market modelling exercise is performed in section 4.2.

4.2 Energy Charge for Offshore Wind

Impact on energy markets. A selective energy injection charge for offshore wind corresponds to an additional variable cost for offshore generators. To recover these additional costs, offshore wind farms will increase their bid values by the value of the injection charge. In contrast with the previously discussed cases, however, there is no impact on the bids by other technologies.

Changes in Dispatch. The aforementioned increase in bid values for offshore wind leads to a reshuffling of the merit order. Compared with other domestic low-variable cost technologies, including other RES, offshore wind becomes more expensive. It is thus curtailed (or not dispatched) with a higher priority than other RES, which may significantly affect total production. Moreover, offshore wind is displaced by other technologies with higher variable cost in the merit order, leading to a welfare loss. The increased costs also lead to a comparative disadvantage of domestic offshore wind compared with generation capacities abroad, resulting in a reduction of exports (for net exporters) or an increase of imports (for net importers) and

[5] Note: the NL figure does not include energy volumes passed on to the distribution grid.

causing additional welfare losses. For a selective injection charge on offshore wind, a wholesale price effect is less likely than with uniform injection charges: it occurs only at times when offshore wind either is the price setting technology or when it prices itself out of the market, i.e. is too expensive for its bids to be accepted. The quantitative relevance of these effects on dispatch is analyzed in section 4.2.2.

Distributional effects. The overall welfare loss due to the injection charge is distributed unevenly among the market participants. Most likely, the dominant effect will be a domestic redistribution from offshore wind producers to consumers, with consequences for support schemes:

- **Domestic producers** of offshore wind energy will likely suffer inframarginal rent reductions. They are either dispatched and not price-setting, leading to a reduction in profits due to the higher costs. When they are no longer dispatched due to the injection charge (i.e. when they priced themselves out of the market), no revenues are generated in the market or in a production-based support scheme.
- **Producers abroad** will benefit from a potential increase in the wholesale prices and/or potentially higher utilization (higher exports), but the quantitative impact is unclear.
- **Domestic consumers** will most likely benefit, as grid tariffs for consumers go down, while the increase in wholesale prices will be less pronounced than with a uniform injection charge and thus likely smaller than the drop in consumer grid tariffs. The impact on privileged consumers (i.e. consumers with discounts on grid charges), paying only reduced grid tariffs, might still be negative, but less so than with uniform injection charge.
- **Consumers abroad** will be adversely affected, but the quantitative impact remains unclear. If the bidding zone subject to the injection charge is a net exporting zone, the injection charge could lead to an increase in the wholesale price or a decrease in congestion rent. If it is a net exporter, congestion income may also rise, but only at times when offshore wind is the price setting technology.

Consequences for support schemes. The bidding behavior in most support schemes is affected by an energy injection charge. If the RES targets shall still be achieved, this could result in a redistribution from tax payers to electricity consumers.

- In a **CfD**-based support scheme, power plants under the CfD (contract for differences) receive compensation payments whenever the reference price is above or below the contractual strike price. In a production-independent CfD, compensation payments are made independent of the plant's own generation in a certain hour, but tied for instance to the production of a reference generator. The revenues under a production-independent CfD are thus unaffected by the injection charge, such that no change in bidding behavior is to be expected. In a production-dependent CfD, compensation payments are tied to the plant's own production, which in case of the injection charge is affected by lower utilization and higher risks due to priority curtailment. This will be taken into account by bidding for a higher strike price. In both cases, the costs for the government will increase due to lower market revenues.

- The lower expected market revenues of offshore wind will drive down bids for support schemes with a **secondary bid component** (i.e. a charge for the right of use of an offshore site) or other lump sum payments. Because of risk aversion, the reduction of lump sum payments might exceed the net present value of payments accumulated from injection charges, yielding a negative net impact of the injection charge. If the rational lump sum payment becomes negative and no support payment is on offer to realize such a compensation, bidders might refrain from bidding under a secondary bid component.
- The so-called „**beauty contest**" is a support scheme with a bid selection based on qualitative criteria, which – similar to the secondary bid component, may be used when all bids amount to zero. In such cases, applicants are awarded the right to use an offshore site based on their quality regarding soft criteria. With lower expected market revenues due to the injection charge, the willingness to excel in costly soft criteria will be reduced or bidders might refrain from bidding altogether if a potential cost reduction in soft criteria is not sufficient to compensate for lower revenues.

4.2.1 Modelling approach

Quantitative Estimation of Impacts. In order to quantify the impact an energy injection charge for offshore wind has on dispatch, it is modelled using Consentec's dispatch model OptEK. The modelling exercise is performed for an already existing scenario for 2030, based on the scenario "National Trends" of the TYNDP 2022. In the results, a reference scenario ("base") without an injection charge is compared to different scenarios with a unilateral, selective energy charge in either Germany or the Netherlands. Key indicators examined are the electricity production from offshore wind, the change in wholesale prices, market revenues for offshore wind, consumer cost and exchange patterns in Germany, the Netherlands and neighboring countries.

Base scenario. In the base scenario (Figure 11), we consider a market model of Europe, focusing on the Netherlands (NL) and Germany (DE or DELU), as well as their interconnectors with Denmark East (DKE) and Norway (NO). The Dutch exclusive economic zone (EEZ) comprises offshore generation capacity of 11.4 GW, the German EEZ host offshore generation capacity of 24.3 GW. All offshore wind farms in this scenario are radially connected to the onshore grid.

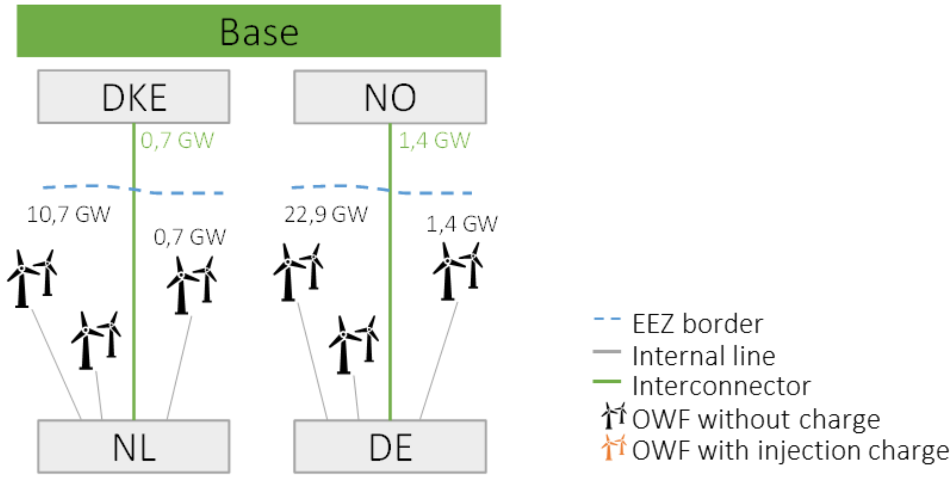
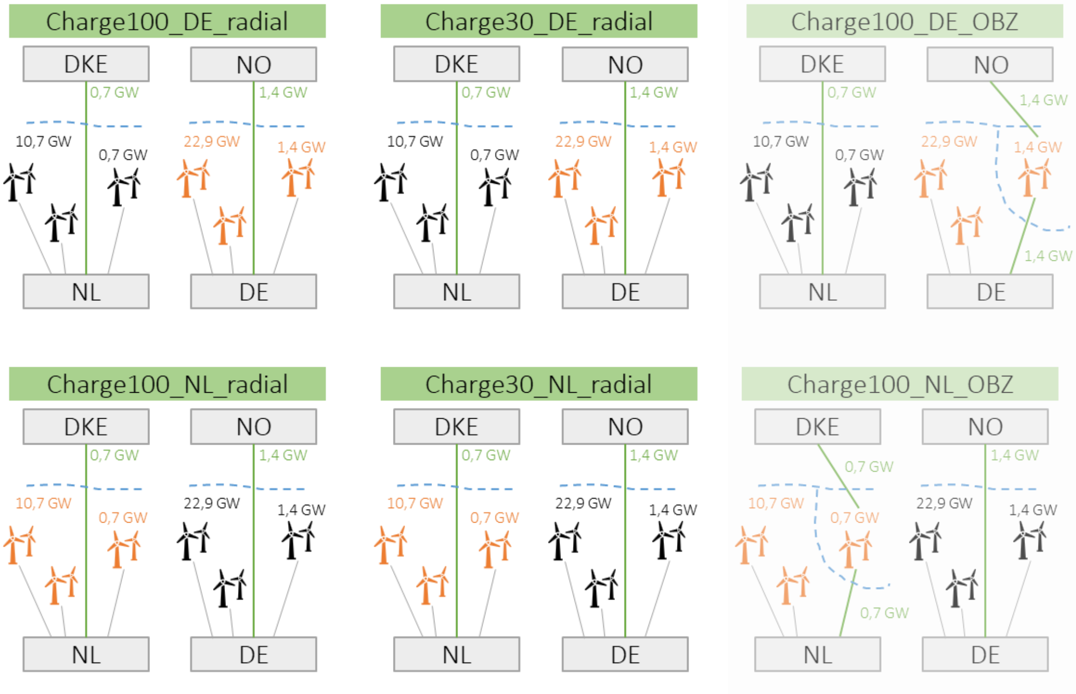


Figure 11. Base scenario without injection charge

Injection charge scenarios. The base scenario is then compared to different scenarios that assume an injection charge for offshore wind in either DE or NL (Figure 12). The injection charge is dimensioned to cover 100 % (scenarios "Charge100") or 30 % (scenarios "Charge30") of offshore cost (roughly, to avoid the need for an iterative approach), respectively. Offshore wind farms can be connected radially (i.e. with an internal connection line) or as hybrids, combining grid connection with interconnection. In the latter cases, a share of the offshore wind farms in the country with an injection charge are located in an offshore bidding zone (OBZ), which is connected via interconnectors both to the country with injection charge and one neighboring bidding zone, while keeping the total exchange capacity unchanged[6]. The following analyses focus on the cases with uniquely radial connections of offshore wind, considering the OBZ cases as a mere sensitivity. Examples:

- In the scenario Charge30_DE_radial, the injection charge is dimensioned to recover 30 % of German offshore grid connection costs by an energy charge on offshore wind (assuming generation at full potential), where all offshore wind farms are connected radially.
- In the scenario Charge100_NL_OBZ, the injection charge is dimensioned to recover 100 % of Dutch offshore grid connection costs by an energy charge on offshore wind (again assuming generation at full potential), where 0.7 GW of the offshore wind farms are hybrid assets in an OBZ, connected with interconnectors to both NL and DKE.

[6] To achieve this, the interconnector between the country with injection charge and its neighboring bidding zone (i.e. between NL and DKE or between DE and NO) is diverted through the OBZ.



Charge100: injection charge applies to 100% of offshore cost
Charge30: injection charge applies to 30% of offshore cost

Figure 12. Scenarios with unilateral energy charge for offshore wind

Modelling inputs. The modelling exercise relies upon an existing scenario based on TYNDP 2022. In order to reflect current developments, the installed capacities and energy injection charges for offshore wind in DE and NL have been adjusted to the values from the table in 4.1.

4.2.2 Quantitative results

Results: Offshore generation. In the base scenario, offshore generation is at about 100 TWh in DE and 85 TWh in NL, while no injection charge is levied. A unilateral energy charge on offshore wind reduces the amount of offshore wind produced domestically. For a charge aiming at 100 % cost recovery, offshore generation in DE is reduced by 24.6 TWh (24 %) or 34.9 TWh (40 %) in NL, respectively. The higher magnitude of the effect in NL is caused by the significantly higher energy charge compared to DE, leading to a stronger increase in generation cost and more situations where offshore wind prices itself out of the market (it becomes more expensive than some gas turbines). For a charge aiming at 30 % cost recovery, the reduction in offshore generation is similar, with a reduction by 18.7 TWh (17 %) for DE and by 30.1 TWh (35 %) for NL.

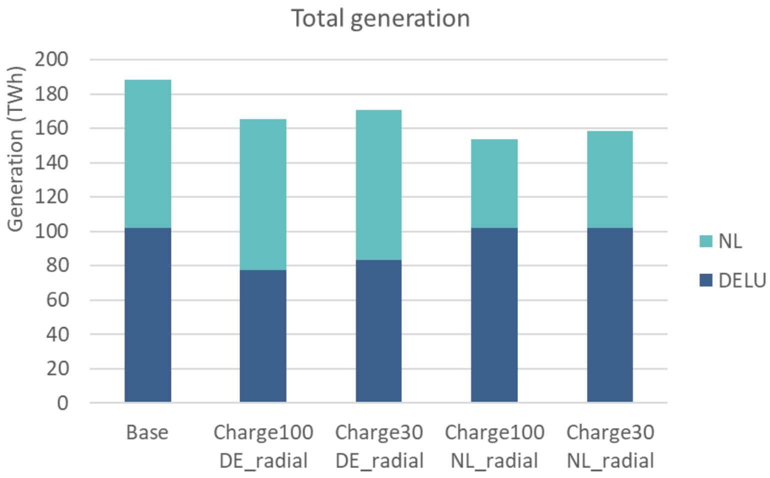


Figure 13. Offshore generation 2030

Results: Revenues of injection charge. The injection charge aims to recover around 3.6 bn € in either of the countries considered (or 1.2 bn € in the 30 % cases) with offshore wind operating at full production potential. Figure 14 illustrates that – due to the reduced offshore generation – only a share of these amounts can be recovered, especially in NL where offshore generation in the 100 % case is reduced even further than in DE.

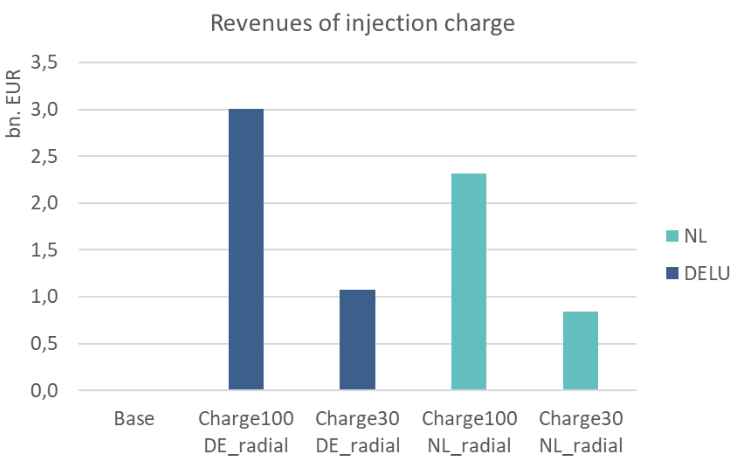


Figure 14. Revenues of injection charge 2030

Results: Offshore curtailment in OBZ sensitivity. In NL, more than 40% of offshore wind generation is curtailed when 100% of offshore grid cost is to be refinanced by injection charge. In DELU, the injection charge is slightly lower, such that less than 25% of offshore generation are curtailed. Comparing the cases “radial” and “OBZ”, relative curtailment (i.e. curtailed energy per generation potential) is higher within the offshore bidding zone than in the onshore bidding zone subject to the injection charge, as there is no domestic consumption within an offshore bidding zone. This is most prominent for an injection charge on DE offshore wind, which leads to curtailment of 75% of the generation within the OBZ.

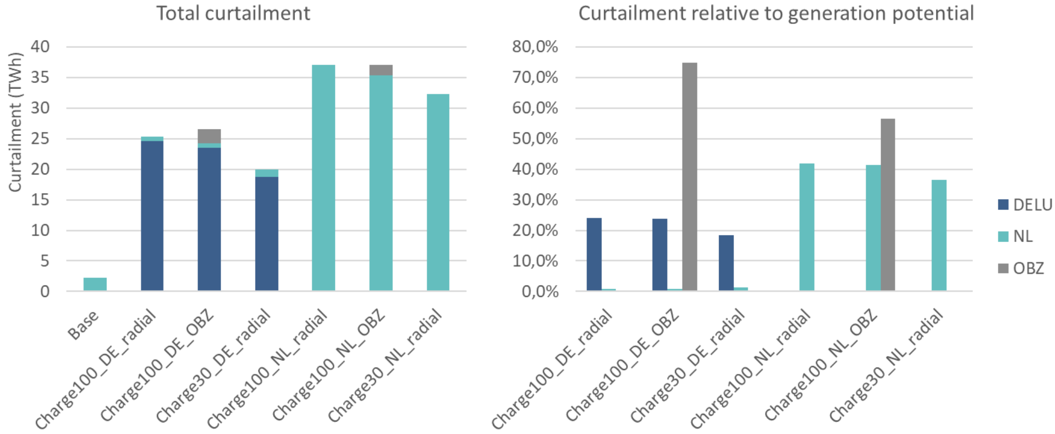


Figure 15. Curtailment of offshore wind due to injection charge in 2030 – OBZ sensitivity

Results: Domestic wholesale prices. An energy injection charge on DE offshore wind farms aiming at 100 % cost recovery raises the domestic wholesale price by up to 4.45 €/MWh (to ca. 58 €/MWh), a corresponding charge in NL domestic wholesale price by up to 12.02 EUR/MWh (to ca. 51 €/MWh). Consequently, the domestic cost of consumption (i.e. the sum of hourly load weighted by hourly price per bidding zone) rises by up to 2.6 bn. € for an injection charge in DE or up to 1.7 bn € for an injection charge in NL. For DE, this is lower compared with the revenues from the injection charge (3.0 bn €), entailing a "gain" for domestic consumers, i.e. the cost increase across domestic consumers is lower than the reduction in consumer grid charges. The same is true for NL, with revenues of 2.3 bn € from the injection charge. Aiming at only 30 % cost recovery significantly reduces the increase in wholesale prices and thus in consumer cost.

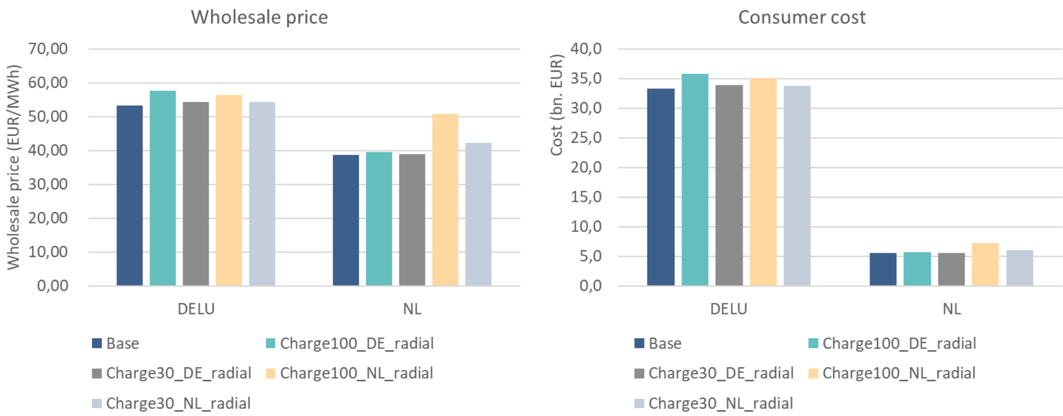


Figure 16. Wholesale prices in DE and NL 2030

Results: Wholesale prices abroad. The injection charge also affects foreign wholesale prices (though at a smaller extent), i.e. the charge is partially passed through via cross-border power trade. The extent depends on the intensity of trade at the respective border. The lowest effects are again perceived when only part of the offshore grid costs is recovered through the charge.

Figure 17. Change in wholesale prices of neighboring countries in 2030

Results: Offshore market revenues. The change in wholesale prices and in offshore generation affect the total revenues (bn €) of offshore wind (both domestic and – via wholesale prices – abroad). Market values of offshore wind (€/MWh) exclude the effect on offshore generation and thus increase in all injection charge cases compared to the base case. However, subtracting the injection charge leaves the domestic offshore wind farms with a smaller profit per MWh, with the exception of NL in the 30% case.

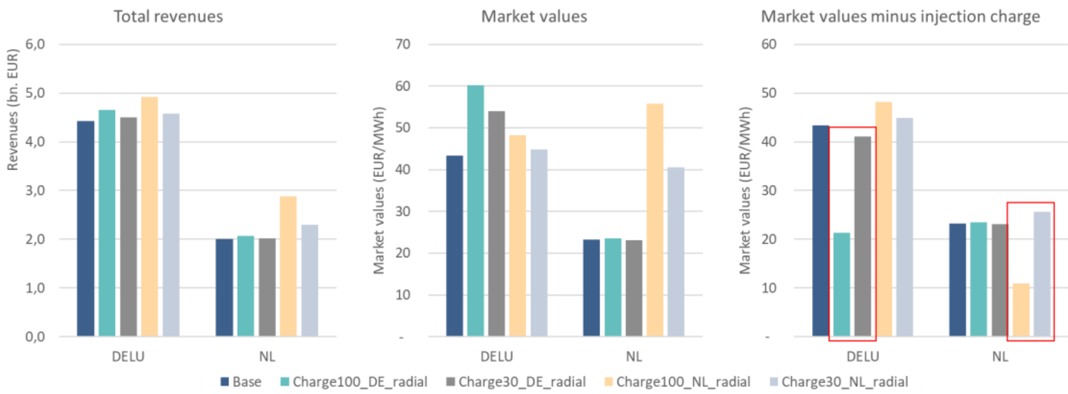


Figure 18. Offshore revenues and offshore market revenues in DE and NL 2030

Result: Exchange patterns. Net exports decrease in the bidding zone with an injection charge. Aiming at 100 % cost recovery, the net position in DE decreases by 15.9 TWh, the net position in NL decreases by 15.1 TWh for 100%, turning the positive Dutch net position into a negative one. To balance the lower domestic net exports, net positions in neighboring bidding zones change accordingly. The impacts on exports from Denmark West (DKW) illustrated in Figure 19 are mainly driven by an injection charge on offshore wind in DE, exports from Belgium (BE) by an injection charge on offshore wind in NL. In both cases, there are major increases also in exports from Sweden (SE), Great Britain (GB) and France (FR).

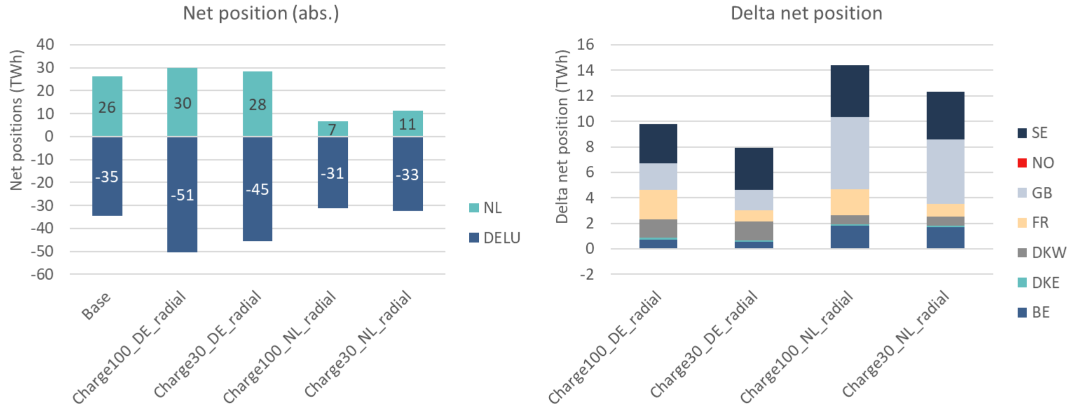


Figure 19. Net positions for DE, NL and net position changes in neighboring countries 2030

Conclusion. Offshore grid connection costs are higher than for all other technologies, leading to substantial cost increases when introducing a selective energy injection charge on offshore wind, higher consumer costs and lower offshore market values. Due to the resulting drop in offshore generation, grid cost cannot be fully recovered. Moreover, the energy charge fails in collecting significant cost contributions from abroad, as cost recovery from abroad is possible only in hours when the country with injection charge is exporting and offshore wind is price setting, but net exports decrease with an injection charge. Instead, the injection charge results mainly in domestic redistribution from offshore wind producers to consumers.

4.3 Connection Charge for Offshore Wind

Connection charges are fixed costs. Their impacts will therefore not differ from those of other fixed costs, which – in equilibrium – will have to be recovered by inframarginal rents (or support payments). All other things equal, an increase of fixed costs will drive down profitability and thus lead to reduction in offshore buildout.

Impact on energy markets. No effect on bidding in short-term markets is expected from connection charges, as they will be sunk before any bids are submitted to the market. There might, however, be an impact on the price levels of long-term PPA concluded before the final investment decision.

Distributional effects. Distributional effects are mostly limited to the country or bidding zone with the connection charge:

- A connection charge will reduce the profits of offshore wind energy if not compensated by support schemes.
- If offshore wind installations remain at the same level, domestic consumers will benefit from lower grid tariffs while not affecting short-term energy markets. Therefore, at least no adverse impact is to be expected on privileged consumers (despite, potentially, higher PPA prices). In order to compensate offshore wind farms for the higher fixed costs, additional support might be needed.

- If offshore wind installations are reduced, consequences are unclear. On the one hand, lower installations mean lower grid costs, and thus lower tariffs because of reduced demand for offshore connections. On the other hand, electricity prices might be higher due to the reduced generation capacity.
- Only second-order effects are to be expected in other countries or bidding zones. With unchanged levels of offshore buildout, there will be no consequences abroad. If offshore buildout is reduced, an increase in wholesale prices is possible.

Consequences for support schemes. The bidding behavior in most support schemes is affected by an energy injection charge. If the RES targets shall still be achieved, this could result in a redistribution from taxpayers to electricity consumers.

- In a **CfD**-based support scheme, power plants under the CfD (contract for differences) receive compensation payments from the government whenever the reference price is above or below the contractual strike price. Increased fixed costs then lead to bids for higher strike prices. Simultaneously, costs for the government will increase due to lower market revenues and a resulting need for higher compensation payments.
- The higher fixed costs with a connection charge for offshore wind will drive down bids for support schemes with a **secondary bid component** (i.e. a charge for the right of use of an offshore site) or other lump sum payments. If the rational lump sum payment becomes negative and no support payment is on offer to realize such a compensation, bidders will refrain from bidding under a secondary bid component.
- The so-called „**beauty contest**" is a bid selection scheme based on qualitative criteria, which – similar to the secondary bid component, may be used when all bids amount to zero. In such cases, applicants are awarded right to use offshore sites based on their quality regarding soft criteria. With higher fixed costs due to the injection charge, the willingness to excel in costly soft criteria will be reduced or bidders might refrain from bidding altogether if a potential cost reduction in soft criteria is not sufficient to compensate for increased costs.

Conclusion. Offshore grid connection costs are higher than for all other technologies, leading to substantial increases in fixed costs and a reduction in profits for offshore wind when introducing a selective connection charge on offshore wind. While no impact on short-term markets is to be expected, the reduced profits may lead to a reduction in offshore buildouts and thus higher prices, if not compensated by support payments. In that case, grid cost can potentially not be recovered fully. The injection charge will result mainly in price increases (if buildout is reduced) or domestic redistribution from taxpayers to electricity consumers (if offshore wind farms are compensated for the increased fixed costs by support payments).

5 Conclusion

Cost recovery. In this study, we primarily analyzed whether injection charges without temporal or spatial variation can help recovering grid investment costs from consumers in other countries. Our findings show that injection charges only achieve this objective under specific conditions. In some cases, injection charges may lead to the opposite effect and increase the financial burden for domestic consumers.

Propagation mechanism. The only mechanism through which injection charges can recover grid costs from foreign consumers is through higher-priced exports. For this, two conditions need to be fulfilled: first the injection charge must lead to an increase in the wholesale price, and second, the network must be and remain a net exporter. Only then domestic consumers have a (net) benefit at the expense of consumers in other networks. This implies that an injection charge that has no impact on the wholesale price – for example because the price-setting generator is in another network or because sunk costs fail to trigger a price spike – will necessarily fail to deliver this objective. Furthermore, if the injection charge raises wholesale prices during periods when the network is importing electricity, this will increase import costs and defeat the cost-recovery objective. Consequently, injection charges only contribute to cross-border cost recovery for net exporting countries.

National vs. European implementation. When injection charges are implemented across many systems, for example in a joint European approach, no market distortions occur. In that case, the dispatch of generators and interconnector usage remain unaffected. A common energy charge thus simply redistributes network costs from net importing to net exporting networks without any impact on spot markets. A unilaterally introduced injection charge, i.e. only introduced in one country, may also work for cross-border network cost recovery. However, it comes with significant side effects. In particular when set high, it distorts plant dispatch, and lead to welfare losses. When turning a net exporting country into an importer, they also defeat the cost-recovery objective. Moreover, unilateral energy charges can lead to significant redistributional effects abroad: they raise wholesale prices in neighboring countries and thereby redistribute benefits from foreign consumers to foreign producers. These redistributions may be much higher than the intended distributional effects.

Effect on industry. A further important insight of this study is the harmful effect of injection charges on consumers who are exempt from network charges or receive network fee rebates (e.g., certain industries). Injection charges increase spot prices while lowering withdrawal charges. This increases electricity bills for consumers who are partially or fully exempt from withdrawal charges. Notably, these exempt consumers are typically more price-sensitive, further exacerbating the issue.

Selective energy charge. An injection charge should be applied uniformly across all generators and not only target specific technologies – in particularly not mostly inframarginal generation such as offshore wind. Charging only specific technologies is most likely not in line with European legislation due to discrimination. Besides, targeting only some technologies would not alter wholesale prices in most hours, and thus strongly limit cost-recovery from abroad.

Capacity charge. Injection charges can only recover costs from abroad if they do not change the network's export status. However, injection charges specified per peak injection (capacity charges) almost certainly change the export-status. They affect the wholesale price only in a few hours per year when they cause high price spikes. This renders the network in these hours into an importer of electricity. Therefore, capacity injection charges are counterproductive for cross-border cost-recovery.

Additional drawbacks. Capacity-based injection charges without temporal or spatial variation have a few additional severe drawbacks. They most likely result in price spikes, which will trigger political and public backlash and may result in strong distributional consequences among consumers and inefficient demand-side response. If price spikes are suppressed, security-of-supply issues may emerge. Furthermore, generators with peaks that do not align with the system peak cannot fully pass on the charge, a particular disadvantage for wind and solar plants that rarely run at nameplate capacity at system peak hours. Over time, this misalignment can reduce the market share of renewables. For these reasons, we advise against using any kind of nationally uniform capacity injection charge, including annual and monthly network usage and connection charges.

Interaction with funding mechanisms. Finally, it is important to note that most foreseen generation investments receive public funding, through renewables support schemes or capacity mechanisms. If these mechanisms set fixed capacity targets, an injection charge without temporal or spatial variation does not affect the overall investment volume or capacity mix. Any additional costs for renewable projects would simply result in higher subsidies or lower revenues from auctioning sites. In essence, this shifts resources from one public pot to another: the revenue raised by injection charges may be redirected to investment funding mechanisms.

Incentives. Injection charges could provide dispatch or investment incentives for generators that do not arise from the current market design. This could be substituting missing locational signals in zonal markets, smoothing peak injection, or internalizing the network costs of electricity exports. However, we recommend not introducing injection charges without a clear understanding of the specific problem they are intended to solve. For many of these externalities, alternative measures may prove more effective and less distortionary. For example, while capacity-based injection charges might encourage peak generation curtailment, they often come with severe side effects. Dynamic tariffs or a reform of support schemes could offer more targeted and efficient solutions. Therefore, injection charges should not be treated as a one-size-fits-all instrument but rather applied selectively and purposefully. Without this focus, they risk being ineffective, distortionary, or even counterproductive.

The case of offshore. Offshore grid connection costs are higher than for all other technologies, leading to substantial cost increases when introducing a selective energy injection charge on offshore wind, higher consumer costs and lower offshore market values. Due to the resulting drop in offshore generation, grid cost cannot be fully recovered. Moreover, the energy charge fails in collecting significant cost contributions from abroad, as cost recovery from abroad is possible only in hours when the country with injection charge is exporting and offshore wind is price setting, but net exports decrease with an injection charge. Instead, the injection charge results mainly in domestic redistribution from offshore wind producers to consumers. A selective connection charge on offshore wind on the other hand would lead to substantial increases in fixed costs and a reduction in profits for offshore. While no impact on short-term markets is to be expected, the reduced profits may lead to a reduction in offshore buildouts and thus higher prices, if not compensated by support payments. In that case, grid cost can potentially not be recovered fully. The capacity injection charge will result mainly in price increases (if buildout is reduced) or domestic redistribution from taxpayers to electricity consumers (if offshore wind farms are compensated for the increased fixed costs by support payments).

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