ECONSTOR
Make Your Publications Visible.

A Service of

ZBW Leibniz-Informationszentrum Wirtschaft
Leibniz Information Centre for Economics

Eicke, Anselm; Khanna, Tarun; Hirth, Lion

Working Paper

Locational investment signals in electricity markets - How to steer the siting of new generation capacity?

Suggested Citation: Eicke, Anselm; Khanna, Tarun; Hirth, Lion (2019) : Locational investment signals in electricity markets - How to steer the siting of new generation capacity?, ZBW – Leibniz Information Centre for Economics, Kiel, Hamburg

This Version is available at:
http://hdl.handle.net/10419/205237

Standard-Nutzungsbedingungen:

Die Dokumente auf EconStor dürfen zu eigenen wissenschaftlichen Zwecken und zum Privatgebrauch gespeichert und kopiert werden.

Sie dürfen die Dokumente nicht für öffentliche oder kommerzielle Zwecke vervielfältigen, öffentlich ausstellen, öffentlich zugänglich machen, vertreiben oder anderweitig nutzen.

Sofern die Verfasser die Dokumente unter Open-Content-Lizenzen (insbesondere CC-Lizenzen) zur Verfügung gestellt haben sollten, gelten abweichend von diesen Nutzungsbedingungen die in der dort genannten Lizenz gewährten Nutzungsrechte.

Terms of use:

Documents in EconStor may be saved and copied for your personal and scholarly purposes.

You are not to copy documents for public or commercial purposes, to exhibit the documents publicly, to make them publicly available on the internet, or to distribute or otherwise use the documents in public.

If the documents have been made available under an Open Content Licence (especially Creative Commons Licences), you may exercise further usage rights as specified in the indicated licence.

WWW.ECONSTOR.EU

Mitglied der Leibniz-Gemeinschaft

WORKING PAPER

Locational investment signals in electricity markets

How to steer the siting of new generation capacity?

Version 2019-10-31

Anselm Eicke[a*], Tarun Khanna[a,b] and Lion Hirth[a,b,c]

[a] Hertie School of Governance, Berlin
[b] Mercator Research Institute on Global Commons and Climate Change (MCC)
[c] Neon Neue Energieökonomik GmbH
*Corresponding author: Anselm Eicke, eicke@hertie-school.org, Hertie School of Governance, Friedrichstraße 180, 10117 Berlin

Abstract - The location of new power generation capacity has a significant effect on the need for transmission infrastructure. Newly constructed power plants increase network losses, investment, and potentially congestion if they are located far from consumption centers. In addition to costs, lack of public acceptance for transmission extension may increase the relevance of geographical steering of generation investments. The primary objective of this paper is to compare the regulatory instruments that provide locational investment signals. We cluster these instruments into five groups: locational electricity markets, deep grid connection charges, grid usage charges, capacity mechanisms, and renewable energy support schemes. We review the use of instruments in twelve major power systems and discuss relevant properties, which includes a quantitative estimate of their strength. We find that most power systems use multiple instruments in parallel and that there seems to be a lack of consensus regarding the choice of instruments. The results also indicate that the efficacy of many instruments is reduced due to a lack of credibility, low levels of transparency, and insufficient spatial and temporal granularity.

The Strategic Scenario Analysis (START) project upon which this publication is based was funded by the German Federal Ministry of Education and Research under Project Number 03EK3046F.

We would like to thank Ingmar Schlecht, Oliver Ruhnau, Laima Eicke, Lars Stephan, Dylan McConnell, Stacey Crowley, Juan Pablo Carvallo, Kenneth Van den Bergh, Iolanda Saviuc, Diana Chklar, Markus Wypior, Mårten Bergman, Andreas Jahn, the participants of the workshop "Locational Investment Signals" and of the YEEES seminar Leuven for valuable comments, expert insights and feedback. All remaining errors remain our responsibility.

Contents

1 Introduction

Transmission expansion needs. The construction of transmission expansion infrastructure is costly, subject to lengthy permitting processes, and is often met by public resistance. However, the integration of newly constructed power generation facilities results in a significant increase in transmission infrastructure needs in many parts of the world. Reasons include the expansion of wind and solar energy. Both are produced at least cost where land is cheap and resource availability is high, which is often far away from energy consumption centers.[1] In addition, the legacy of regional energy monopolies is fading 20 to 30 years after restructuring the electric power industry in many parts of the United States and Europe. Historically, they have been the primary investors in local generation capacity. In Europe, national power markets are also increasingly closely integrated, which has resulted in a rising long-distance trade of power, and by association, in load flows.

The location of demand and supply. One option to reduce the strain on the network infrastructure is to site generation assets and end users closer to each other. Such locational steering can either be applied to generators or to consumers. Siting generation closer to load centers has an effect similar to the effect of placing energy-intensive industries in areas with an energy surplus. This paper focuses on the locational steering of generation only. Politically, it is much easier to focus on revenue differences associated with generation compared to discriminating against consumers. However, future research could also consider locational incentives that target electricity consumption.

Zonal markets. In Europe, zonal electricity markets prevail. A textbook zonal electricity market does not provide any locational incentive within a zone, which implies that the choice of where to invest is driven only by costs. In the case of wind and solar energy, this choice is usually driven by resource quality and land price, whereas the costs associated with coal-fired power plants are mainly a function of coal transportation costs.

External effects. The lack of locational signals means that the costs of grid losses, expansion, and congestion are not priced. Economically speaking, this absence is an externality: originators of locational integration grid costs do not incur the costs that they created. This leads to inefficient resource allocation, with generation capacity being installed too far from consumers and grid investments being too large compared to the social optimum.

Locational instruments. Unlike textbook zonal markets, most real-world power systems do have regulations that provide locational signals to generators. Many regulations outside the market provide such signals, including grid connection charges, grid usage charges, capacity mechanisms, and renewable energy support schemes. Some power markets have introduced spatial granularity into the market itself in the form of smaller zones or locational pricing. We use *locational instruments* as an umbrella term for this variety of regulations. The primary

[1] One out of many examples is the German power system: most renewable energy generators are being built in the north and the east of the country whereas major load centres are in the south.

purpose of this paper is to discuss locational instruments from a theoretical perspective and review their use empirically.

Instrument-specific literature. A vast amount of published literature covers on many of these instruments – Google Scholar reports 4,100 papers related to “locational marginal pricing” alone. However, this body of research often does not consider the instruments as locational investment incentives. Locational pricing, for example, is generally viewed as a dispatch incentive (Joskow, 2008), and grid charges are widely considered to be a cost recovery mechanism (Olmos & Pérez-Arriaga, 2009). We review some of the publications that focus on locational investment incentives throughout the paper.

Comparative literature. Literature that compares locational investment incentives across instruments is scarce. Hadush et al. (2011) examine market splitting, loss factors, grid usage charges and grid connection charges associated with European case studies. The authors assess each instrument’s effect on investment decisions based on criteria stability, predictability and strength. Brunekreeft et al. (2005) suggest that additional locational instruments complement locational marginal pricing to signal the efficient location of generation investments. The authors base their argument on the observation that locational marginal prices only recover about 20-30% of total grid costs in practice (Pérez Arriaga et al., 1995), and therefore do not fully internalize actual locational value differences of generation. They discuss grid usage charges and deep grid connection charges as supplemental locational instruments. Keller and Wild (2004) assess how coordination between transmission and generation investment can take place in liberalized power markets. To do so, the authors examine locational investment signals arising from transmission pricing. Nikogosian et al. (2019) analyzed grid connection charges, regional quotas, and regional premiums with respect to steering the siting of renewable energy assets in Germany. Their study concludes that among these three, regional quotas are the most effective and easiest to implement in the context of the German energy market. Locational investment signals are considered as a means of reducing grid congestion by Hirth et al. (2018). In their categorization, the authors cluster instruments in a manner similar to that which was employed in this study. To the best of our knowledge, a systematic review of the different classes of instruments has not been conducted so far.

Contributions. This objective of this paper is to close that gap in the literature by providing a comparative review of locational investment signals applicable to generators. More specifically, our contribution to the literature is three-fold. First, we propose nine dimensions to characterize locational instruments. Secondly, we review the locational instruments used in twelve power systems and finally, we introduce a simple methodology to quantify the strength of these instruments and employ it.

Findings. We find that every power system employs at least one instrument, and most systems use multiple locational instruments in parallel. In practice, most of the analyzed locational electricity markets apply regulation on top of a granular market to steer the location of investments. We further observe that instruments differ significantly in design, and there does not appear to be a “silver bullet” instrument, which represents the best option for all systems. The efficacy of many of the locational instruments is reduced due to lack of credibility, low levels of transparency, and insufficient spatial and temporal accuracy.

Structure. The remainder of this paper is structured along our three contributions: Section 2 presents our analytical framework, Section 3 identifies which and where instruments are used, and Section 4 quantifies.

2 Nine relevant characteristics of instruments

The effect of locational instruments on investment decision-making depends on their design. This section proposes nine distinct design characteristics that influence efficacy and nature of the *locational signals* that such instruments provide. In the following section, we apply these characteristics to structure the review of locational instruments in our sample and discuss their implications.

1. Price or quantity. Locational instruments can be designed as price or quantity instrument. For price-based instruments, the difference in the cost or revenue between locations is determined by the regulator, for example grid usage charges that are differentiated by location. By contrast, quantity instruments are characterized by the upper or lower capacity thresholds in a region. Regional quantity limits for renewable energy deployment are an example of this. In an efficient market, this type of instrument translates into a resulting locational price signal. Price-based instruments benefit investors by making it easier to ascertain value differences between different locations. Integration costs that result from connections at certain locations can be transferred directly to project developers. By contrast, quantity-based instruments are valuable because they provide simple and effective locational steerage and quantity constraints (e.g., limited transmission capacity is easy to account for). Most instruments identified in this study are price-based.

2. Per energy or per capacity. Locational signals remunerate or charge generators based on the total amount of energy produced (MWh) or the generation capacity installed (MW). Depending on the design of these instruments, different technologies are affected differently. Capacity-based signals have a stronger impact on technologies with a low capacity factor, such as peaking plants or renewable energy sources, while energy-based instruments have a more significant effect on generators with high capacity factors such as base load plants. To support this point, compare two hypothetical generators. Peak generator P with a capacity of 2 MW is operated 1000 hours per year, and base load generator B has 1 MW of capacity and is operated for 8000 running hours. An instrument that creates a wedge of 10 €/kW between two locations (i.e., a capacity-based instrument) will impact P's net present value twice as much as B's. By contrast, an instrument that creates a wedge of 1 €/MWh between two locations (i.e., a production-based instrument) will affect B four times stronger than P.[2]

[2] In the first case, the impact of the instrument on the NPV of P is 20,000 € whereas its impact on B is 10,000 €. In the second case, the impact on P is just 2000 € annually while the impact on B is 8000 €.

3. Temporal granularity. The value difference of generation between two locations varies over time. Time-invariant instruments fail to reflect this. We explain this by way of the example of two interconnected regions: a surplus region S and a deficit region D. In S, generation exceeds demand most of the time; the opposite is the case for D. In a long-term equilibrium and without lumpiness in grid investments, the marginal value difference between two locations equals the marginal network costs of transmitting electricity between them. In hours when power flows from S to D, generation in D has a higher value than in S because it reduces the use of the network and thereby reduces marginal network costs. This value difference rises with increasing costs of congestion management and transmission losses. When no grid constraints occur, it is close to zero and a negative value difference implies a power flow from D to S. Neither constant energy-based instruments nor capacity-based instruments reflect this temporal variability (Figure 1). When grid congestion is present in the predicted direction (i.e., from S to D), the locational signal is often too weak. In hours without grid congestion, the signal unnecessarily incentivizes generation by D and even aggravates grid congestion when S temporarily lacks supply.

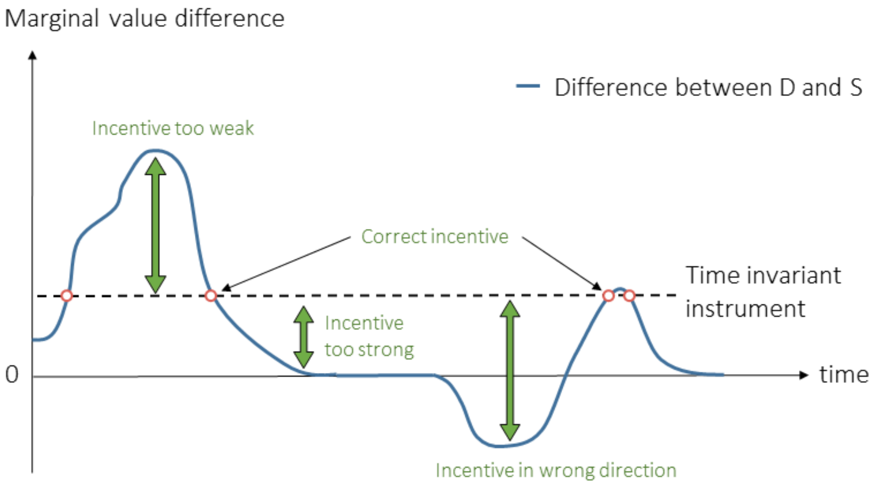

Figure 1. Time-invariant locational signals cannot reflect the marginal value difference between two locations, which varies over time.

4. Spatial granularity. How well signals reflect grid constraints depends on multiple properties including their spatial resolution. Some instruments have a nodal resolution, whereas others result in uniform signals within a region. Depending on the grid topology, a zonal resolution may be insufficient to reflect bottlenecks in the grid, while a zonal design is less complex, which results in improved transparency. On the other hand, nodal granularity is prone to the abuse of market power when prices are not set administratively because only one or just a few suppliers are connected at each node.

5. Credibility and transparency of signals. For an investment decision, the expected price signals foreseen by the investor matter, while the signals as they materialize do not. Hence, the more credible and predictable a price signal is, the more likely it will have an impact on an investment decision. Price signals tend to be more predicable if they occur only once with the investment (e.g., grid connection charges, support schemes), or if they are kept stable over long periods of time (e.g. grid usage fees adjusted once every 10 years). A transparent and rule-based determination of signals also improves credibility. Methods and assumptions employed to determine locational signals are available to the public in some cases, though this is not always the case. One way to provide information on future locational value differences is the dissemination of grid investment plans.

6. Ex-ante or ex-post calculations. Locational signals arising from regulation can be differentiated between ex-post and ex-ante signals. Ex-ante signals are obtained from system models that estimate the future network usage of a generator. Ex-post determined signals are based on the historical use of grid infrastructure. Ex-post signals may be less credible because they are difficult to predict. On the other hand, ex-post signals can have a positive impact on the dispatch of generation if charges can be reduced through certain types of consumer behavior (e.g., by reducing generation at times of network congestion).

7. Premium or penalty. The difference between the locational signals of two different locations may affect siting decisions. Hence, locational signals can be implemented as a premium (payment), as a penalty (charge), or as combination thereof. How an instrument is designed depends on whether it employs the concept of revenue neutrality or cost recovery. Cost neutrality can be achieved when premiums paid by some generators are financed by penalties to others. Such an instrument design does not increase the average cost of power generation, whereas a penalty-only scheme does result in higher generation costs.

8. New or incumbent generation. Some instruments only affect new generators, while others affect all of them. Targeting existing generators is not efficient because they cannot change their location. Such an approach may also increase regulatory uncertainty and may therefore deter future investment. On the other hand, a system that discriminates against new generators compared to existing generators may impede investment if designed as penalty-only system.

9. Signal strength. Obviously, not the mere existence, but the magnitude or strength of signals is relevant for siting decisions. The stronger the signal, the more likely it affects the location of a new generator. However, locational instruments are not the only source of locational signals. Examples for locational signals that do not result from regulation include land purchase and lease costs, local commodity prices, and the availability of resources.

We discuss the types of instrument associated with the first eight characteristics in Section 3, and the quantification of locational signal strength is considered in Section 4.

3 Review of locational instruments

This section provides an overview of the current locational instruments applied in the selected countries. We first present our review approach, and design options are then described instrument by instrument. We then show where instruments are utilized and discuss them using their previously described characteristics.

3.1 Case selection and review approach

Case selection. We review twelve power systems on their use of locational instruments. To this end, we study systems in Chile, France, Germany, India, Mexico, Norway, Sweden, and the United Kingdom, CAISO, PJM, and ERCOT in the United States, and the National Electricity Market (NEM) in eastern and southern Australia. We selected these power systems because they employ liberalized power markets and provide sufficient data transparency.[3] We also aimed for geographic and market design diversity (i.e., zonal and locational marginal pricing).

Clustering. In total, we were able to identify 28 locational instruments. Most instruments carry specific names, often in the local language. To provide an overview and compare features, we clustered all locational instruments into the following five groups based on their economic workings:[4]

- locational electricity markets (i.e., sub-country zones or locational marginal pricing)
- grid connection charges (i.e., one-off costs for connecting to the grid)
- grid usage charges (i.e., ongoing charges for using the grid)
- capacity mechanisms, such as capacity markets, payments, and local tenders
- renewable support schemes such as feed-in-tariffs

Instrument selection. All power systems use some form of grid charge, most have support schemes for renewable energy, and many use capacity mechanisms. However, these instruments are uniform across the power system in many cases. For the purposes of this paper, we are interested in these instruments only to the extent that they (a) apply to generators and (b) have locational granularity (i.e. they differ from one site to another). Only when both conditions hold, an instrument provides a signal to steer generation investment geographically. Often, such instruments are primarily designed for other purposes such as cost recovery, wealth distribution, or security of supply. In some instances, the instrument is not intended to provide a locational signal to investors.

Ambiguous clustering. The proposed grouping is not unambiguous. Unlike others, we classify market splitting and locational marginal pricing as one instrument due to their structural similarities. In the literature, deep grid connection and grid usage charges are often collectively considered as grid charges (Pérez-Arriaga & Smeers, 2003). In addition, the distinction between capacity mechanisms and renewable support schemes is often not clear-cut. For instance, Mexico's clean energy support scheme supports nuclear power plants, some types of gas turbines, and renewable energy sources through capacity and energy payments.

Sources. The primary literature reviewed in this study includes national regulation as well as reports published by international organizations and scientific articles as secondary literature. To validate our findings, we conducted 11 interviews with national experts, and discussed results with 15 experts and stakeholders at a workshop held in Berlin in February 2019.

---

[3] India has officially a liberalised power market and (most importantly for our analysis) generators are free to choose the location of their asset.

[4] A similar grouping has been proposed in Maurer et al. (2018) and Hirth et al. (2018).

3.2 Locational electricity markets

Description. Locational markets provide signals through a spatial granularity of the power market itself and thus differ from all other instruments that work on top of the market. We distinguish between two types of locational electricity markets: locational marginal pricing (also known as nodal pricing) and market splitting. Locational marginal prices account for short-term marginal costs of generation and transmission at each node in the network and are certainly the best known locational instrument. Schweppe et al. (1988) were the first to elaborate that market design. Since then, locational marginal pricing has been introduced in many markets and discussed extensively in the literature (e.g. Green, 2004; Neuhoff and al. 2013; Hamoud and Bradley, 2004; Hogan, 1999; Weibelzahl, 2017), though the focus is often on dispatch incentives. Another method of introducing spatial granularity in electricity markets is to split power systems into multiple smaller zones. Under this so-called market splitting, price differences reflect limited transmission capacity and network losses between zones. Maurer et al. (2018) identify regulatory risk of reconfigured pricing zones as the main drawback of market splitting. Grimm et al. (2016a, b) assess the combined effect of market splitting and various network charging regimes on investments.

Locational electricity markets in our sample. Among our sample, nine power systems feature locational electricity markets. CAISO, Chile, ERCOT, Mexico and PJM introduced locational marginal pricing while Australia, India, Norway, and Sweden split their power system into several zones. [5] The spatial granularity of these instruments differs significantly between countries, which also reflects the geography and density of the population (Table 1).

Table 1: Spatial resolution of locational electricity markets

Locational marginal pricing	
PJM	10300 nodes
CAISO	9700 nodes
ERCOT	8000 nodes
Mexico	2417 nodes
Chile	49 nodes

Market splitting	
India	13 zones
Australia	5 zones
Norway	5 zones
Sweden	4 zones

Features of locational electricity markets. Locational electricity markets are price-based instruments; local prices per MWh provide signals for dispatch and investment decisions. Because prices are determined in real time, the temporal resolution of locational electricity markets is high. Prices reflect the temporal variability in the value difference between locations and are therefore the sole instruments that provide suitable dispatch incentives. However, the credibility of signals arising from locational electricity markets is limited due to the high frequency of price variations and their difficult predictability (Brunekreeft et al., 2005). Even more problematic, significant deviations of current prices from their long-term

[5] The classification of a power system is to some extend arbitrary. Often impacted by national borders, the size of power systems varies strongly, see for example the cases of India and Norway.

equilibrium result from the lumpiness of transmission investment.[6] Green (2003) therefore argues that locational marginal prices may even incentivize wrong locations. Transparency in grid investments is key to increase predictability in future locational value differences and avoid investment in locations where grid extension will take place soon. The spatial granularity is high for locational marginal prices but comparably low for market splitting, depending on the size of zones. Locational electricity markets affect both existing and newly constructed generators.

3.3 Grid connection charges

Description. A grid connection charge is a single payment to the network operator for connecting a plant to the grid. In some countries, generators are charged the costs of connecting to the nearest substation ("shallow connection charges"). Elsewhere new generation projects must finance expansion and upgrades in the grid infrastructure that become necessary following the new connection ("deep grid connection charge"). Deep grid connection charges internalize a portion of the grid extension costs (i.e. investors are charged for the grid extension they cause). A locational signal arises because these costs vary by location and depend on the existing grid. The use of deep grid connection charges to internalize costs of the transmission system has been discussed extensively in the literature (Olmos & Pérez-Arriaga, 2009; Swider et al., 2008; Vogel, 2009).

Deep grid connection charges in our sample. Among the selected power systems, six apply an instrument that we classify as a deep grid connection charge, including CAISO, France, Mexico, PJM, Sweden, and Norway. Table 2 presents the basic characteristics of each approach. Beyond our sample, ENTSO-E provides an overview of deep grid connection charges in Europe (ENTSO-E, 2018).

Table 2. Properties of grid connection charges

CAISO	Payments serve as financial security: the TSO reimburses the interconnection customer the cost of the network upgrades over a period of up to five years. A locational signal arises from a cap of reimbursement. This cap is reviewed annually and lies at $70 per kW of generator capacity (CAISO, 2019b) as of 2019; higher costs will not be reimbursed.
France	New renewable energy generators are charged regionally and differentiated from contributions ("quote-parts") for grid extension (RTE, 2014). In exchange, grids are built in advance and prioritized access to the transmission system is given to these technologies. These charges are uniform within a region, but strong differences exist between regions. The instrument is purely designed for cost-recovery.
Mexico	Generators only pay deep grid connection charges if the new line is not part of the national grid extension plan. In exchange for the payment, investors

[6] Only hypothetical nodal pricing (Hirth et al. 2018) without lumpiness in network extension and without market power correctly reflects all value differences.

	receive the revenues of the sale of financial transmission rights (FTR) for the corresponding line (SENER, 2018).
PJM	Each generator or transmission project bears the cost for required interconnection facilities. Interconnection projects are awarded once per year to better account for shared transmission extension.
Sweden	The plant operator bears the costs of connection by paying the so-called network tariff that includes cost for additional lines and substations. The grid operator is not obliged to connect new projects to the grid if network capacity is insufficient.
Norway	Deep grid connection charges are only applied in the case of radial grid connections (NVE, 2018). The customer's contribution to the investment costs is capped at a share of 50%. This charge was implemented in 2019, and the old regime is in place for planned projects until 2022.

Features of deep grid connection charges. All deep grid connection charges are levied per unit of installed capacity and therefore affect technologies with lower capacity factors more severely. The geographical resolution of grid connection charges is high if calculated for every grid connection point individually. Its locational signal does not vary over time and consequently does not reflect the value difference between locations. If the charge is known before the final investment decision, the instrument results in a very credible locational signal; as a one-time payment, the locational signal does not vary after the project's commissioning. Transparency in the complex and often ambiguous process is an issue for many real-world instruments. We were not able to identify the precise methodology used to determine charges in most cases. Often, costly connection studies must be commissioned from the network operator first to identify suitable locations. Given the many assumptions necessary (Reneses et al. 2003), this process of calculating deep grid connection charges is prone to political influence and lobbying. In theory, connection charges could also be negative, that is generators receive a premium for network connection in certain locations. In practice, this is not the case in any of the systems reviewed. Several challenges result from the fact that grid connection charges affect new generators. For example, sharing expenses between first and later investors is difficult, especially if subsequent investments are not predictable. In practice, the first generator finances grid infrastructure, which is then, due to its lumpiness, used by followers. This may result in a wait-and-see problem with a postponing effect on investment (Swider et al., 2008). A second investment barrier results from the fact that deep grid connection charges imply high upfront costs for investors. Consequently, system costs may be larger than necessary because project developers usually face higher financing costs than regulated system operators.

3.4 Grid usage charges

Description. Grid usage charges are fees for the use of the transmission and distribution system. They are regulated and designed to (at least partly) recover expenses incurred by the system operator. These can comprise capital expenses for building and maintaining grid infrastructure, and operational expenses, such as for system services, transmission losses, and congestion management. While in some systems, costs are simply passed on to consumers, other countries have developed an elaborate system of charges based on the cost-causalities principle. This is the case under cost reflective charging, where the costs of each line are passed on to the consumers and generators who use it (Olmos & Pérez-Arriaga, 2009). For example, Gammons et al. (2011) found that locational transmission tariffs can lead to significantly lower overall costs in the British transmission system due to a placement of generation capacity that reduces infrastructure requirements.

Locational grid usage charges in our sample. Australia, India, Norway, Sweden, and the UK apply location specific grid usages that are paid by generators. All grid usage charges are implemented as a price instrument, but the precise design differs significantly between countries (see Table 3). Grid usage charges are imposed per MWh (Norway and Australia), per MW (India), or both (UK, Sweden). The charges are adjusted frequently, at least once a year (Australia, India, and UK) or even on a weekly basis (Norway, Sweden). Australia, Norway, and Sweden have per MWh charges that are proportional to the zonal electricity price; the level of charges is determined for each substation through the multiplication of the zonal electricity price with a site-specific factor. This factor reflects the marginal transmission losses and sometimes the cost of grid congestion and it differs by location. Under such a design, stronger signals arise for technologies that generate electricity during high price periods (peakers) and weaker signals for technologies of which the generation coincides with low prices (e.g. wind and solar). The spatial resolution of charges varies significantly: the UK is split into 27 zones, Norway and Australia charge transmission fees on a substation-level, and charges in Sweden depend on the geographical latitude. In India, charges are calculated by node, and then aggregated per utility. In Australia, Norway, Sweden, and the UK, grid usage charges can be negative (i.e. generators receive payments at certain locations).[7] In all cases in our sample, grid usage charges are determined ex-ante and affect new and existing generators.

Table 3: Characteristics of grid usage charges

Country	per	Spatial granularity	Premium or penalty?	Frequency of adjustment	Temporal granularity
UK	MWh and MW	27 Zones	Both	Yearly	Time-invariant
Sweden	MW	155 Substations	Penalty only	Weekly	Time-invariant (within the week)
	MWh	155 Substations	Both	Yearly	Multiplier on zonal price
Norway	MWh	~800 Substations	Both	Weekly	Multiplier on zonal price
Australia	MWh	~1000 Substations	Both	Yearly	Multiplier on zonal price
India	MW	59 Entities	Penalty only	Yearly	Time-invariant

Annotation: UK's grid usage charges are specified per capacity but the calculation of charges accounts for the number of full load hours. For simplicity, we classify them as capacity-based instruments in the following.
Sources: (AEMO, 2019b; CERC, 2018; National Grid, 2018; NVE, 2018; Svenska Kraftnät, 2019)

[7] In Europe cost reflective charging of generators is constraint under current legislation. The value of the annual average transmission charges paid by producers must be within a range of 0 to 0,5 EUR per MWh for most countries and only slightly higher for a few selected countries (European Commission, 2010).

Features of grid usage charges. Allocating grid costs according to the consumer pays principle has proven difficult in practice because there is no indisputable method to compute the electrical utilization of lines by agents (Olmos & Pérez-Arriaga, 2009). Hence, especially in distribution grids, proxies are used to maintain transparency and reproducibility, which reduces the accuracy of the instrument. In contrast to grid connection charges, grid usage charges also affect existing generators. Thus, changes to the tariff design imply a risk for generators. For instance, new transmission lines and investment in generation have caused locational benefits to fall by large margins in Australia. More specifically, location-specific marginal loss factors, which are proportional to generator's revenues, have decreased by up to 11% on average in certain regions from 2018 to 2019 (AEMO, 2019b). This, in turn, had material financial implications that were often unforeseen by existing and intending market participants, which highlights the importance of credible and transparent grid expansion plans.

3.5 Capacity mechanisms

Description of instrument. Capacity mechanisms remunerate plant operators for providing capacity to the power system. One problem common to many capacity mechanisms is a uniform incentive within the entire system. Nieto and Fraser (2007) find that this lack of locational granularity may worsen capacity and transmission problems in specific locales, even while it resolves the capacity problem in the aggregate. Some capacity mechanisms therefore have a location-specific component (i.e. the mechanism incentivizes capacity on a sub-system scale).

Locational capacity mechanisms in our sample. Among the selected cases, Chile, CAISO, France, Germany and PJM have a location specific capacity mechanism (Table 4) whereby all but Chile apply quantity-based mechanisms.[8] In PJM and CAISO, load serving entities are obliged to contract for firm capacity at a sub-system level. While an organized market in PJM facilitates this process (PJM, 2019a), CAISO's load serving entities are bound to contract for capacity directly (CAISO, 2019a). In France, a tender for a power plant in the import-constrained region Brittany[9] was set up on top of a non-location-specific capacity market (CRE, 2014). Germany's local capacity procurement by tender[10] incentivizes the construction of four new power plants in the south of the country. These plants will provide redispatch services to grid operators and do not sell electricity on the wholesale market. By contrast, Chile applies a price-based capacity mechanism. The Chilean energy commission determines nodal capacity prices as the cost of investing in a diesel-fired turbine that runs at system's peak demand. All generators are remunerated based on their historical availability at peak demand (ex-post). While the geographic granularity of the capacity payments coincides with that of the energy market in Chile, this is not the case in the US, where CAISO and PJM employ nodal energy markets but zonal capacity markets.

---

[8] The German network reserve was excluded because it only encompasses existing power plants and therefore does not provide an investment incentive.

[9] The winning project was a 450 MW combined cycle plant located in Landivisiau, Brittany. The region was specified in the tender, but no site was predeveloped.

[10] In German: *Besondere netztechnische Betriebsmittel*

Table 4: Characteristics of capacity mechanisms

	Regulator sets	Spatial granularity	Product duration	Ex-ante or ex-post
Chile	Price	49 nodes	6 months	Ex-post
CAISO	Quantity	10 areas	undefined	Ex-ante
France	Quantity	1 node (single plant)	20 years	Ex-ante
Germany	Quantity	4 areas	10 years	Ex-ante
PJM	Quantity	20 sub-systems	1 year	Ex-ante

Sources: (CAISO, 2019a; CNE, 2018; CRE, 2014; PJM, 2019a; Tennet, 2019)

Features of locational capacity mechanisms. By their very nature, capacity mechanisms are specified per MW and are therefore time-invariant instruments. Their credibility varies significantly. Tenders in France and Germany offer high investment security due to their long duration; the other capacity mechanisms are less credible due to shorter contract durations and price volatility. Whereas the Chilean approach of a price-based instrument provides more price-security, the uncertainty of contracted capacity undermines the reliability objective of the instrument (Nieto & Fraser, 2007). All instruments are implemented as premiums that awards both new and existing generators.

3.6 Renewable energy support schemes

Description of instrument. Globally, 135 countries use support schemes for the deployment of renewable energy (REN21, 2019). Renewable energy sources have outpaced conventional capacity in terms of newly added capacity since 2014 (IRENA, 2019), and many observers expect most future generation investment to concentrate on renewable energy sources (Bloomberg New Energy Finance, 2019). Support schemes can have very different forms: feed-in tariffs, renewable portfolio standards, and subsidized loans are just a few examples. While some of these support schemes are not location-specific, others are. The effect of renewable support schemes on the locational decision of new generators has been discussed among others by Wagner (2019), Ropenus et al. (2011) and Hiroux & Saguan (2010).

Locational renewable support schemes in our sample. We have identified location-specific renewable support schemes in Germany and Mexico (see Table 5).[11] Locational signals either results from price discrimination in the winner selection process of auctions (e.g. premiums or penalties in certain regions) or stem from quantity regulation (e.g. floors for certain regions). In both Mexico and Germany, the selection of winning bids in auctions has a locational component in some cases. The Mexican auction for clean energy aims to reflect the costs of locations designated for new installations. Price bids are adjusted by locational premiums and penalties; projects in supply-constrained regions get awarded at higher bid prices and vice versa. These locational markers are determined ex-ante through an optimization model that

[11] Net metering tariffs are a major driver for renewable deployment in the US. They can be considered as an indirect renewable support scheme. Some utilities, e.g. in Austin (Texas) offer these tariffs with a locational component. There exist, however, no uniform regulation on these tariffs (Jahn et al., 2019). We therefore excluded them from our analysis.

maximizes the economic surplus of additional generation for each node. A similar approach has been chosen for two types of renewable energy auctions in Germany. First, in onshore wind auctions, adjustment factors for each location are determined according to the average wind speed ("Referenzertragsmodell"). Although this instrument does not explicitly account for grid constraints, it has a similar effect given that wind speeds and grid constraints arise in similar regions. Second, in technology-neutral renewable auctions, projects are penalized when connected to distribution grids where renewable feed-in exceeds local demand ("Verteilernetzkomponente"). The penalties depend on the already locally installed capacity and differ for wind and solar. Another locational instrument in Germany is the limitation of wind deployment for the most grid-constrained regions through a quantity cap in the auction design ("Netzausbaugebiet"). When binding, this constraint results in lower support levels in the constraint area and may lead to higher support in the unconstrained area. Hence, Germany uses three locational mechanisms in its support schemes.

Table 5: Characteristics of renewable support schemes

	Type	Spatial granularity	Technologies	Temporal granularity
Mexico	Premium and penalty	53 zones	Bioenergy, geothermal, hydropower, nuclear, efficient CHP, wind and solar	Time-invariant
Germany (Referenzertragsmodell)	Premium and penalty	Plant specific	Wind	Time-invariant
Germany (Verteilernetzkomponente)	Penalty	98 districts	Wind and solar	Time-invariant
Germany (Netzausbaugebiet)	Quantity cap	2 zones	Wind	Time-invariant

Sources: (BMWi, 2017, 2019; FA Wind, 2019; IRENA, 2017)

Features of locational renewable support schemes. All four locational renewable support schemes are energy-based instruments; premiums and penalties are paid per MWh generated. The locational marker has no temporal granularity and is time-invariant. In all price instruments, the determination of the locational signal occurs in a transparent manner ex-ante and is fixed for 15 to 20 years. They therefore provide one of the most credible signals. A major drawback of locational incentives in renewable energy support schemes is that only new and subsidized renewable energy sources are targeted. Market-driven renewable investment as well as conventional generation and storage remain unaffected by the instrument. This limited scope may lead to an inefficient allocation of technologies.

3.7 Incidence of instruments across our sample

Case overview. Summarizing the findings of our empirical review yields four interesting insights (see Table 6). First, each of the twelve power systems reviewed uses at least one locational instrument. Second, most power systems actually employ multiple instruments. Sweden for example has split its electricity market into four zones, applies deep connection charges, and has location-specific grid usages charges per kW and location-specific charges per MWh. PJM and CAISO apply locational marginal pricing, deep connection charges, and a zonal capacity market. Germany has three distinct mechanisms within its renewables support scheme in addition to a less significant capacity instrument. Third, most power systems that have spatial granular markets, use additional instruments to steer investment. Among these, some of the countries (Australia, Norway and Sweden) implemented energy-based grid usage charges that provide additional (distorting) dispatch incentives. Finally, no instrument is used across all power systems.

Table 6: Prevalence of locational instruments applicable to generators

	Australia	Chile	France	Germany	India	Mexico	Norway	Sweden	UK	USA - CAISO	USA - ERCOT	USA - PJM
Locational electricity markets	■	■	□	□	■	■	■	■	□	■	■	■
Grid connection charges	□	□	■	□	□	■	■	■	□	■	□	■
Grid usage charges	■	□	□	□	■	□	■	■	■	□	□	□
Capacity mechanisms	□	■	■	■	□	□	□	□	□	■	□	■
RE support schemes	□	□	□	■	□	■	□	□	□	□	□	□

■ Locational instrument □ No locational instrument

Key point: Every single power system uses at least one locational incentive and even most systems with locational electricity markets use additional instruments to steer investment.

4 Quantification of instruments

The strength of the signal strongly matters for investment decisions. In this section, we propose and apply a simple method to quantify and compare the strength of the 28 instruments where data is available.

4.1 Quantifying the signals in original units of measurement

Method. The presented instruments provide financial incentives, and we determined the magnitude of additional revenues and costs arising from them. We proxy the strength of each instrument as the *maximal spread of locational signals between locations* Δs_{max}, which is defined in Eq. (1)

$$\Delta s_{max} := s_+ - s_- \tag{1}$$

where s_+ is the locational signal at the location where it is strongest and s_- where it is weakest. So Δs_{max} is the maximal impact the instrument can have among two alternative locations for an investment. This approach can be used to compare highly diverse instruments by isolating the locational effect from the overall level of payments and revenues.

Example I. To illustrate the approach, we exemplarily quantify the locational signal that results from British Transmission Network Use of System charges (TNUoS) on onshore wind energy[12]. The highest charges apply to the region of Glenglass in North Scotland and the lowest (negative) charges in Central London. TNUoS are reported in pounds per kW. From Eq. (1), we obtain:[13]

$$s_+ = 30\ \text{£/kW} \cdot \text{a}$$

$$s_- = -8\ \text{£/kW} \cdot \text{a}$$

$$\Delta s_{max} = s_+ - s_- = 38\ \text{£/kW·a} \approx 43\text{€/kW} \cdot \text{a}$$

Application. Similarly, this metric was applied to our sample of instruments. To maintain comparability, we quantified all signals for the year 2018 when possible. Δs_{max} is expressed in EUR[14] per kWh or per MW depending on how the instrument is specified. For time-variant instruments, we use annual averages to determine the most expensive and the cheapest location. The locational signal for quantity-based instruments, such as regional capacity limits for renewables, is not explicit. We then use the maximal spread of the instrument between constrained regions. Table 7 shows that the magnitude of signals Δs_{max} varies strongly. A direct comparison between instruments is difficult due to the diverseness of units. We therefore estimated the strength of all signals in an equivalent energy charge (in EUR per MWh), which is discussed in the next subsection.

[12] Unlike all other instruments, TNUoS are specified per capacity but also depend on the capacity factor. We assume 3000 full load hours and utilize the level of charges applicable in 2018/2019 (National Grid, 2018).

[13] We distinguish costs of energy (e.g. €/MWh) and yearly costs of capacity (e.g. €/kW·a) by notation.

[14] We use the exchange rate as of 01.01.2019 to convert costs into EUR.

Table 7: Strength of locational signal applicable to generators

	Australia	Chile	France	Germany	India	Mexico	Norway	Sweden	UK	USA - CAISO	USA - ERCOT	USA - PJM
Locational markets (€/MWh)	28	7			0	13	1	2		14	19	21
Connection charges (€/kW·a)			70			*	*	85*		1080*		540*
Grid usage charges (€/MWh)	17						9	3				
Grid usage charges (€/kW·a)	17				36			4	43			
Capacity mechanisms (€/kW·a)		21	94	*						*		23
RE support schemes (€/MWh)				32		11						

*No or poor data availability — Locational instrument — No locational instrument

Annotations: Further information and sources are listed in Table A.1. Note that the tile for Germany's renewable support only covers the locational signal of the wind auction adjustment factor ("Referenzertragsmodell"). The penalty in overloaded distribution grids ("Verteilernetzkomponente") results in a maximal signal of 8.8 €/MWh (not represented in Table 7). Because the locations with strongest and weakest signal do not coincide, signals cannot be superposed. Germany's quantity constraint ("Netzausbaugebiet") was never binding in 2018 and did not result in a locational signal.

4.2 Conversion into Euro per MWh

Converting per capacity to per energy. To convert annual capacity-based payments, such as grid usage charges specified per installed capacity, into equivalent payments ($c_{\text{per MWh}}$) for every MWh generated, annual costs ($c_{\text{annual, per MW}}$) are divided by the number of full load hours (FLH) (Eq. (2)). Since the conversion of per-kW signals into per-MWh terms depends on the capacity factor, and some instruments are technology-specific, we use two exemplary cases: (i) a combined cycle gas turbine with 5000 full load hours (capacity factor of 57%) and (ii) onshore wind power with 3000 full load hours (34%).

$$c_{per\ MWh} = \frac{c_{annual,\ per\ MW}}{FLH} \tag{2}$$

Annualization. We convert nonrecurring payments such as grid connection charges into a yearly annuity over the expected lifetime (Eq. (3)). The annuity factor itself depends on lifetime (n) and weighted average cost of capital (WACC). For both technologies, we assume a WACC of 5% and a lifetime n of 25 years.

$$c_{annual,\ per\ MW} = c_{lifetime,\ per\ MW} \cdot \frac{WACC}{1-(1+WACC)^{-n}} \tag{3}$$

Example. Revisiting the British TNUoS, Eq. 2 can be used to express Δs_{MAX} of 43 EUR per kW (see 4.1) as an equivalent energy charge. Assuming 3000 full load hours for wind generation, we obtain an equivalent of around 14 EUR per MWh. The British TNUoS is a special case since charges per capacity also depend on technology type and the capacity factor (National Grid, 2018). Therefore, not only the equivalent energy charge but also the capacity charges differ for wind and gas turbines (Table 8).

Table 8. Strength of the locational signal of TNUoS expressed per unit of capacity and per unit of generation

		€/kW p.a.	€/MWh
Renewable	Wind power (3000 FLH)	43	14
Mid-load	Combined cycle gas turbine (5000 FLH)	34	7

4.3 Findings

Overview. Tables 9 and 10 display our quantitative findings. They present the strength of each instrument expressed in EUR per MWh for a combined cycle plant and a wind power turbine. Values for gas and wind diverge due to different capacity factors and because some instruments are technology specific. We found that in countries which apply several instruments, the locations where the signal is strongest and weakest often do not coincide across instruments. In these cases, the locational signals cannot be superposed, and the maximal signal resulting from all instruments is lower than the sum of the individual signals.

Combined cycle plant. Most of the instruments we studied apply to gas-fired power generation, except for support schemes and certain grid fees. Table 9 summarizes the strength of each instrument. A few observations are worth noting. First, the magnitude of instruments varies significantly, with some having virtually no effect and others introducing a cost spread of around 20 EUR per MWh. This is quite significant compared to levelized costs of combined cycle plants of 64-72 EUR per MWh in Europe[15]. Secondly, the overall impact is very limited in some countries, where not a single strong instrument exists (e.g., in Sweden, Norway, UK and India) and very large in others (e.g., in Australia and PJM). Thirdly, each class of instruments contain examples with very weak signals and others where signals are very strong, which indicates no instrument class always results in weak signals while another persistently results in strong signals.

Wind energy. Wind energy is affected by all instruments apart from some capacity mechanisms and the grid usage charge in India. The general findings for gas-fired generation also hold true for wind. In addition, we found that some instruments have a stronger effect on wind than on gas. This can be explained by the lower capacity factor of wind, which results in higher locational signals of capacity-based instruments. The locational signal emerging from renewable support schemes also turned out to be relatively strong compared to other

[15] Own calculation based on assumptions for CCGT stated in 4.2 and cost data from the World Energy Outlook, 2018 (IEA, 2019)

instruments. Stronger incentives than shown in the table arose, for example in Mexico's first clean energy auctions in 2016, where locational signals of winning bids had a maximal spread of 38 EUR per MWh (IRENA, 2017).[16]

Table 9: Magnitude of locational signals for combined cycle gas power plant (expressed in EUR per MWh)

	Australia	Chile	France	Germany	India	Mexico	Norway	Sweden	UK	USA - CAISO	USA - ERCOT	USA - PJM
Locational electricity markets	28	7			0	13	1	2		14	19	21
Grid connection charges						*	*	1*		15		8*
Grid usage charges	17				7		9	4	7			
Capacity mechanisms		4	19*	*						*		5
RE support schemes												

*No or poor data availability

Locational instrument (conv.)

No locational instrument (conv.)

Table 10: Magnitude of locational signals for wind generation (expressed in EUR per MWh)

	Australia	Chile	France	Germany	India	Mexico	Norway	Sweden	UK	USA - CAISO	USA - ERCOT	USA - PJM
Locational electricity markets	28	7			0	13	1	2		14	19	21
Grid connection charges			2			*	*	2*		26*		13*
Grid usage charges	17						9	4	14			
Capacity mechanisms										*		8
RE support schemes				32		11						

*No or poor data availability

Locational instrument (wind energy)

No locational instrument (wind energy)

[16] The locational markers in all (not rewarded) areas even differed by 70 EUR per MWh.

Caveat. Three considerations are important to acknowledge when interpreting results. First, a weak locational signal either indicates that the instrument does not fully reflect the value difference of generation between locations, or that this difference is just as small as indicated by the signal. Inversely, a strong locational signal does not necessary imply that future investment should or is likely to occur at prioritized locations. Second, many other aspects also affect the profitability of projects; for example construction costs and resource availability may vary significantly between locations. And finally, results for grid connection charges should be treated with care. Since data availability is poor, the few identified figures for this instrument can only be viewed as proxies.

Limitations. The approach employed in this study was used to analyze the instruments' impact at the two most extreme areas. This is a helpful proxy that can be used to better understand the potential impact of each instrument. However, the metric Δs_{max} does not provide information about any other location, and it is sensitive to outlying values. A distribution function of an instrument's strength, as opposed to a single scalar, would provide richer information, but could not be constructed due to a lack of data. Given the number of instruments, such quantification would also be difficult to compare. Finally, we emphasize again that the signal's magnitude is only one out of many indicators that determine how effective an instrument affects the siting decision of new capacity.

5 Summary and conclusions

Instrument types. A variety of instruments provide locational incentives, which can steer generation investments within a power system. We cluster instruments into five groups: locational electricity markets, grid connection charges, grid usage charges, capacity mechanisms, and renewable energy support schemes. Our analysis highlights that all twelve power systems, which we reviewed, employ at least one locational instrument. Most systems, including power systems that implemented locational electricity markets, use multiple instruments in parallel.

Properties of instruments. Several properties determine how effective instruments steer investments at certain locations. We identify nine relevant design elements that often entail trade-offs. These trade-offs result in some weaknesses of all instruments. Specifically, a lack of credibility, low levels of transparency, and insufficient spatial and temporal granularity decrease the efficacy of many instruments. Credibility is highest for deep grid connection charges, most renewable support schemes, and some capacity mechanisms that provide predictable locational investment incentives due to their long contract duration. Transparency in methods, models, and assumptions is key to enhance credibility and reduce investor's risks. We could, however, not unveil the precise determination of most instruments – hence a further improvement of transparency is still possible in most cases. The spatial granularity varies significantly between instruments. At a minimum, it should reflect relevant network bottlenecks to give correct incentives. The temporal resolution of most instruments is low, which implies that most instruments do not reflect marginal value differences over time. These results are in line with the observation that none of the instruments is used across all countries.

Summary of empirical review. The quantification of instruments reveals a significant variation in their strength. Many instruments provide stronger locational signals for renewable energy sources than for conventional generation. This is, among others, due to an intrinsic disadvantage for technologies with lower capacity factors resulting from the many capacity-based instruments.

Policy recommendation and further research. Well-designed locational signals can encourage generators to consider transmission- and congestion-related costs in their siting decision. While this paper shall foster discussions related to the need for and trade-offs between different instrument types and designs, a more detailed analysis of the effect of locational instruments on different technologies is left open for future research.

References

AEMO. (2019a). *Data dashboard – Electricity price statistics for Australia*. Retrieved from https://aemo.com.au/Electricity/National-Electricity-Market-NEM/Data-dashboard#average-price-table

AEMO. (2019b). *Marginal loss factors for the 2019-20 financial year*. Retrieved from https://www.aemo.com.au

Bloomberg New Energy Finance. (2019). *New Energy Outlook 2019*. Retrieved from https://about.bnef.com/new-energy-outlook/

BMWi. (2017). *Verordnung zu den gemeinsamen Ausschreibungen für Windenergieanlagen an Land und Solaranlagen*. Retrieved from https://www.bmwi.de/

BMWi. (2019). *Gesetz für den Ausbau erneuerbarer Energien (Erneuerbare-Energien-Gesetz—EEG 2017)*. Retrieved from http://www.gesetze-im-internet.de/eeg_2014/EEG_2017.pdf

BNetzA. (2017). Gemeinsame Ausschreibungen von Windenergieanlagen an Land und Solaranlagen. Retrieved from https://www.bundesnetzagentur.de/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/Ausschreibungen/Technologieuebergreifend/GemeinsAusschr_node.html

Brown, P. R., & O'Sullivan, F. (2019). *Shaping photovoltaic array output to align with changing wholesale electricity price profiles*. *Applied Energy*. https://doi.org/10.1016/j.apenergy.2019.113734

Brunekreeft, G., Neuhoff, K., & Newbery, D. (2005). Electricity transmission: An overview of the current debate. *Utilities Policy*, *13*(2), 73–93. https://doi.org/10.1016/j.jup.2004.12.002

CAISO. (2019a). Annual report on market issues and performance 2018. Retrieved from http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

CAISO. (2019b). Fifth Replacement FERC Electric Tariff. Retrieved from http://www.caiso.com/Documents/ConformedTariff-asof-Apr1-2019.pdf

CENACE. (2018). *Zonas de Precios—RE Auction 2018*. Retrieved from https://www.cenace.gob.mx/Paginas/Publicas/MercadoOperacion/SubastasLP.aspx

CENACE. (2019). Historia de Precios de Energía Marginales Locales. Retrieved from https://www.cenace.gob.mx

CERC. (2018). *Slab rates for PoC Charges & Losses 2018—Order No. L-1/44/2010-CERC*. Retrieved from http://nerldc.org/Docs/webupload/PoC%20charges%20and%20losses%20order%20for%20Apr%20to%20June%202018.pdf

CNE. (2018). Fijación de precios de nudo promedio del systema eléctrico nacional. Retrieved from https://www.cne.cl/

CNE. (2019). Precio Medio de Mercado 2018. Retrieved from https://www.cne.cl/precio-medio-de-mercado-2/

CRE. (2014). Landivisiau: Informations complémentaires sur le contexte du projet. Retrieved from http://pref29.alkante.com/sit_1_ALK/upload/actu/1301/document_reponse_AE.pdf

ENTSO-E. (2018, May). *Overview of Transmission Tariffs in Europe: Synthesis 2018*. Retrieved from https://docstore.entsoe.eu/Documents/MC%20documents/TTO_Synthesis_2018.pdf

European Commission. (2010). *EU Regulation 838/2010*. Retrieved from https://eur-lex.europa.eu

FA Wind. (2019). 8. Ausschreibung für Windenergieanlagen an Land. Retrieved from https://www.fachagentur-windenergie.de/fileadmin/files/Veroeffentlichungen/FA_Wind_Analyse_8_Ausschreibung_Wind_an_Land.pdf

Gammons, S., Druce, R., & Strbac, G. (2011, September). *Locational Transmission Charging in Decarbonised Power Markets*. Nera Economic Consulting.

Green, R. (2003). Cost Recovery and the Efficient Development of the Grid. In F. Lévêque, *Transport Pricing of Electricity Networks* (pp. 137–153). https://doi.org/10.1007/978-1-4757-3756-1_5

Green, R. (2004). *Electricity Transmission Pricing: How much does it cost to get it wrong?* Retrieved from http://ceepr.mit.edu/files/papers/2004-020.pdf

Grimm, V., Martin, A., Schmidt, M., Weibelzahl, M., & Zöttl, G. (2016). Transmission and generation investment in electricity markets: The effects of market splitting and network fee regimes. *European Journal of Operational Research*, *254*(2), 493–509. https://doi.org/10.1016/j.ejor.2016.03.044

Grimm, V., Martin, A., Weibelzahl, M., & Zöttl, G. (2016). On the long run effects of market splitting: Why more price zones might decrease welfare. *Energy Policy*, *94*, 453–467. https://doi.org/10.1016/j.enpol.2015.11.010

Hadush, S., Buijs, P., & Belmans, R. (2011). *Locational Signals in Electricity Market Design: Do they really matter?* Presented at the 8th International Conference on the European Energy Market, Zagreb, Croatia. https://doi.org/10.1109/EEM.2011.5953086

Hamoud, G., & Bradley, I. (2004). Assessment of Transmission Congestion Cost and Locational Marginal Pricing in a Competitive Electricity Market. *IEEE Transactions on Power Systems*, *19*(2), 769–775. https://doi.org/10.1109/TPWRS.2004.825823

Hiroux, C., & Saguan, M. (2010). Large-scale wind power in European electricity markets: Time for revisiting support schemes and market designs? *Energy Policy*, *38*(7), 3135–3145. https://doi.org/10.1016/j.enpol.2009.07.030

Hirth, L., Schlecht, I., Maurer, C. W., & Tersteegen, B. (2018). *Zusammenspiel von Markt und Netz im Stromsystem*.

Hogan, W. (1999). *Transmission Congestion: The Nodal-Zonal Debate Revisited*. Retrieved from https://sites.hks.harvard.edu/fs/whogan/nezn0227.pdf

IEA. (2019). *WEO 2018 Assumptions*. Retrieved from https://www.iea.org/weo/weomodel/

IEX. (2019). Area Prices | Indian Energy Exchange Ltd. Retrieved 28 October 2019, from https://www.iexindia.com/marketdata/areaprice.aspx

IRENA. (2017). *Renewable Energy Auctions: Analysing 2016*. Abu Dhabi.

IRENA. (2019). Renewable capacity highlights. Retrieved from Renewable Capacity Statistics 2019 website: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/

Jahn, A., O'Reilly, M., & Deutsch, M. (2019). *Photovoltaik-Eigenversorgung: Erfahrungen aus den Net-Energy-Metering-Programmen der USA*.

Joskow, P. L. (2008). Capacity payments in imperfect electricity markets: Need and design. *Utilities Policy*, *16*(3), 159–170. https://doi.org/10.1016/j.jup.2007.10.003

Keller, K., & Wild, J. (2004). Long-term investment in electricity: A trade-off between co-ordination and competition? *Utilities Policy*, *12*(4), 243–251. https://doi.org/10.1016/j.jup.2004.03.002

Maurer, C., Zimmer, C., & Hirth, L. (2018). *Nodale und zonale Strompreissysteme im Vergleich*. Retrieved from https://www.bmwi.de/Redaktion/DE/Publikationen/Studien/nodale-und-zonale-strompreissysteme-im-vergleich.pdf?__blob=publicationFile&v=4

National Grid. (2018). *Final Tariffs for 2018/19*. Retrieved from https://www.nationalgrid.com/sites/default/files/documents/Final%20TNUoS%20Tariffs%20for%202018-19%20-%20Report.pdf

Nieto, A. D., & Fraser, H. (2007). Locational Electricity Capacity Markets: Alternatives to Restore the Missing Signals. *The Electricity Journal*, *20*(2), 10–26. https://doi.org/10.1016/j.tej.2006.12.006

Nikogosian, V., Özalay, B., Lück, L., Schönefeld, M., Chang, H., & Sprey, J. (2019). *Regionale Steuerung zur Synchronisation von EE- und Netzausbau* (p. 30). Retrieved from https://www.e-bridge.de/wp-content/uploads/2019/07/20190710_Reg.-Steuerung_MS_innogy_public.pdf

Nordpool. (2019). Historical Market Data. Retrieved from http://www.nordpoolspot.com/historical-market-data/

NVE. (2018). The Norwegian power system. Grid connection and licensing. Retrieved from http://publikasjoner.nve.no/faktaark/2018/faktaark2018_03.pdf

Olmos, L., & Pérez-Arriaga, I. J. (2009). A comprehensive approach for computation and implementation of efficient electricity transmission network charges. *Energy Policy*, *37*. https://doi.org/10.1016/j.enpol.2009.07.051

Pérez Arriaga, I. J., Rubio Odériz, F. J., Puerta Guitérrez, J. F., Arcélus Ogando, J., & Martin, J. (1995). *Marginal Pricing of Transmission Services. An Analysis of Cost Recovery*. *IEEE Transactions on Power Systems*(1), 65–72. https://doi.org/10.1109/59.373981

Pérez-Arriaga, I. J., & Smeers, Y. (2003). Pricing of electrical transmission and distribution networks. In *Transport Pricing of Electricity Networks* (pp. 175–204). Retrieved from DOI: 10.1007/978-1-4757-3756-1

PJM. (2019a). PJM Learning Center—Capacity Market (RPM). Retrieved from https://learn.pjm.com/three-priorities/buying-and-selling-energy/capacity-markets.aspx

PJM. (2019b). *Summary of 2018/2019 Base Residual Auction Results*. Retrieved from www.pjm.com

REN21. (2019). Renewables 2019 Global Status Report. Retrieved from https://www.ren21.net/gsr-2019

Ropenus, S., Jacobsen, H. K., & Schröder, S. T. (2011). Network regulation and support schemes – How policy interactions affect the integration of distributed generation. *Renewable Energy*, *36*(7), 1949–1956. https://doi.org/10.1016/j.renene.2010.12.015

RTE. (2014). Accueil des énergies renouvelables sur le réseau: RTE se mobilise. Retrieved from https://www.rte-france.com/sites/default/files/schemas-regionaux-enr-2014_1.pdf

RTE. (2018). Panorama de l'électricité renouvelable en 2018. Retrieved from https://www.rte-france.com/sites/default/files/panoramat4-2018-hd.pdf

Schweppe, F. C., Caramanis, M. C., Tabors, R. D., & Bohn, R. E. (1988). *Spot Pricing of Electricity*. https://doi.org/10.1007/978-1-4613-1683-1

SENER. (2018). *Manual para la Interconexión de Centrales Eléctricas y Conexión de Centros de Carga*. Retrieved from http://www.diputados.gob.mx/LeyesBiblio/regla/n565.pdf

Svenska Kraftnät. (2019). Tariff/Charges | Svenska kraftnät. Retrieved 17 June 2019, from https://www.svk.se/en/stakeholder-portal/Electricity-market/Connecting-to-the-grid/stamnatstariffen/tariffcharges/

Swider, D. J., Beurskens, L., Davidson, S., Twidell, J., Pyrko, J., Prüggler, W., … Skema, R. (2008). Conditions and costs for renewables electricity grid connection: Examples in Europe. *Renewable Energy*, *33*(8), 1832–1842. https://doi.org/10.1016/j.renene.2007.11.005

Tennet. (2019). *Besondere netztechnische Betriebsmittel: TenneT erteilt Zuschlag an Uniper*. Retrieved from https://www.tennet.eu/de/news/news/besondere-netztechnische-betriebsmittel-tennet-erteilt-zuschlag-an-uniper/

Vogel, P. (2009). Efficient investment signals for distributed generation. *Energy Policy*, *37*(9), 3665–3672. https://doi.org/10.1016/j.enpol.2009.04.053

Wagner, J. (2019). Grid Investment and Support Schemes for Renewable Electricity Generation. *The Energy Journal*, *40*(2). https://doi.org/10.5547/01956574.40.2.jwag

Weibelzahl, M. (2017). Nodal, zonal, or uniform electricity pricing: How to deal with network congestion. *Frontiers in Energy*, *11*(2), 210–232. https://doi.org/10.1007/s11708-017-0460-z

Annex

Table A.1: Calculation of locational signals

Country	Instr.	Name of instrument	Max	Min	Difference in €	Source
Australia	LM	Spot prices 2018-19	128 AU-$/MWh	83 AU-$/MWh	28 €/MWh	(AEMO, 2019a)
Chile	LM	Nodal prices 2018 (2nd half)	33.6 CL-$/kWh	28 CL-$/kWh	7 €/MWh	(CNE, 2019)
India	LM	Area prices 2018	3990	3973	0.2 €/MWh	(IEX, 2019)
Mexico	LM	Nodal prices 2016, Spot market	62 US-$/MWh	48 US-$/MWh	12.6 €/MWh	(CENACE, 2019)
Norway	LM	Elspot Prices 2018	44.08 €/MWh	43.25 €/MWh	0.83 €/MWh	(Nordpool, 2019)
Sweden	LM	Spot prices 2018	467 SEK/MWh	446 SEK/MWh	2 €/MWh	(Nordpool, 2019)
US - CAISO	LM	Nodal prices 2017, Day ahead	41.4 US-$/MWh	25.5 US-$/MWh	14.2 €/MWh	(Brown & O'Sullivan, 2019)
US - ERCOT	LM	Nodal prices 2017, Day ahead	39.7 US-$/MWh	18.1 US-$/MWh	19.4 €/MWh	(Brown & O'Sullivan, 2019)
US - PJM	LM	Nodal prices 2017, Day ahead	47.3 US-$/MWh	23.5 US-$/MWh	21.3 €/MWh	(Brown & O'Sullivan, 2019)
France	GC	Quote parts for RES 2018	70.46 €/kW·a	0 €/kW·a	70.46 €/kW·a	(RTE, 2018)
Mexico	GC	Deep grid connection charges	n/a	n/a	n/a	No data available
Norway	GC	Deep grid connection charges	n/a	n/a	n/a	No data available
Sweden	GC	Deep grid connection charges	85 €/kW	0 €/kW	6 €/kW·a	(Swider et al. 2008)
US - CAISO	GC	Deep grid connection charges	1200 US-$/kW	0 US-$/kW	1080 US-$/kW	(Mills and Wiser 2009)
US - PJM	GC	Deep grid connection charges	600 US-$/kW	0 US-$/kW	540 US-$/kW	(Mills and Wiser 2009)

Australia	GU	Marginal loss factors FY 2018-2019 (multiplied with average zonal price)	132.9 AUD/MWh	106.0 AUD/MWh	17 €/MWh	(AEMO, 2019b)
India	GU	POC slab rate 2018	330 INR/kW·month	79 INR/kW·month	36 €/kW·a	(CERC, 2018)
Norway	GU	Marginal loss factors multiplied with zonal electricity price	6.00 €/MWh	-3.4 €/MWh	9.4 €/MWh	(NVE, 2018)
Sweden	GU	Capacity fee for generation 2018	55 SEK/kW·a	24 SEK/kW·a	3 €/kW·a	(Svenska Kraftnät, 2019)
Sweden	GU	Energy for generation 2018	16.72 SEK/MWh	-10.9 SEK/MWh	3 €/MWh	(Svenska Kraftnät, 2019)
UK	GU	TNUoS 2018/2019 for wind (3000 FLH)	30 GBP/kW·a	-8 GBP/kW·a	43 €/kW·a	(National Grid, 2018)
UK	GU	TNUoS 2018/2019 for natural gas (5000 FLH)	20 GBP/kW·a	-10 GBP/kW·a	34 €/kW·a	(National Grid, 2018)
Chile	CM	Capacity prices 2018 (2nd semester)	5544 CLP/kW·month	4224 CLP/kW·month	21 €/kW·a	(CNE, 2019)
France	CM	Landivisiau gas plant tender	94 €/kW·a	0 €/kW·a	94 €/kW·a	(CRE, 2014)
Germany	CM	Local capacity procurement by tender	n/a	0 €/kW·a	n/a	No data available
US - CAISO	CM	Capacity obligation	n/a	n/a	n/a	No data available
US - PJM	CM	Base residual auction results 2018/19	223.1 USD/MW·day	152.7 USD/MW·day	23.1 €/kW·a	(PJM, 2019b)
Germany	RE	Referenzertragsmodell (as of 01/2018)	81.27 €/MWh	49.77 €/MWh	31.5 €/MWh	(BMWi, 2019)
Germany	RE	Verteilernetzkomponente (as of 01/2018)	8.8 €/MWh	0 €/MWh	8.8 €/MWh	(BMWi, 2017)
Germany	RE	Netzausbaugebiet – Avg. of highest accepted bids (2018)	60.4 €/MWh	60.4 €/MWh	0 €/MWh	(FA Wind, 2019)
Mexico	RE	Green Energy Auction 2018	7.62 USD/MWh	-4.95 USD/MWh	11 €/MWh	(CENACE, 2018)

Abbreviations of instruments

LM - Locational electricity markets
GC - Grid connection charges
GU - Grid usage charges
CM - Capacity mechanisms
RE - Renewable energy support schemes