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Keywords wholesale electricity markets, market clearing, centralization, decentralization, unit-commitment, self-dispatch

JEL Classification D44, L13, L94

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Central- versus Self-Dispatch in Electricity Markets[1]

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Abstract

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1 Introduction

Electricity is a perishable good; once it is produced there is limited storage capacity in the power system. This means that electricity has to be consumed at the same moment as it is being produced. Often the only slack is provided by the rotating mass in generators, motors and turbines. These machines will spin faster, increasing in frequency, when there is more energy stored in the system. Conversely, the frequency decreases when there is less electricity stored in the system. Electric machines can be destroyed if the frequency deviates too much from the nominal frequency, which is 50 Hz in Europe and 60 Hz in US. If the frequency gets out of bounds, some machines will, to protect themselves, automatically disconnect and the system will collapse. A power collapse is very costly for society and it takes several hours to restore the system. As an example, it took about 12 hours to restore the system after the Great Blackout of 2011 in southwestern US. Therefore, it is imperative to keep production and consumption in balance every single minute.

It is challenging to continuously keep the system in balance. Consumption and renewable energy can vary unpredictably. The demand for electricity often is price insensitive; for instance, many households pay a fixed price that does not fluctuate from hour to hour. Still, consumers are free to suddenly increase or decrease consumption without notice, regardless if the market frequency approaches its bounds. Similarly, renewable output is intermittent by nature, varying unpredictably from one minute to another. Besides these challenges, technical network and production constraints have to be considered. For example, there are intertemporal constraints on how quickly producers can increase and decrease their output. Moreover, some plants are not fully divisible, i.e. they can only produce in a narrow output range, while other plants may have minimum downtimes. Start-up costs and intertemporal constraints imply that the cost of producing during one hour depends on the output in adjacent hours. The empirical study by Reguant (2014) shows that this effect has a strong influence on the bidding behaviour in Spain. Another issue is that the marginal cost could be decreasing in some output intervals. Such non-convexities imply that a producer may require a price above its marginal cost in those intervals to avoid making a loss. In order to manage all of these issues and to get a feasible and socially efficient dispatch, electricity production is coordinated by a system operator when delivering electricity in real-time.

Automatically controlled primary and secondary spinning reserves, with a response time shorter than minutes, will balance out all sudden shocks. Longer lasting shocks are managed by the real-time market. To keep the system in balance on a minute by minute basis, the system operator decides how much each plant should increase/decrease its production; thus, electricity markets have central unit commitment for changes in real-time. In most markets, there is a penalty for changes that have not been cleared in the real-time market. At this stage, the system operator needs to take all aspects of the network into account and it normally needs detailed knowledge about costs, ramp-rates and locations of plants in order to make technically feasible and socially optimal decisions. This information is partly submitted to the system operator when a production plant is registered, while some information can be submitted as part of a bid.

All electricity markets are coordinated by a system operator in real-time, but central coordination ahead of delivery differs between markets. Decentralized electricity markets have little coordination ahead of delivery, while centralized electricity markets could be coordinated by a market operator long before delivery. The US markets tend to be centralized, while European markets are more decentralized and less coordinated. Wilson (2002) compares the two approaches. In this survey, we revisit this discussion in light of progress that has been made in the literature during the last 15 years.

Many plants have long ramping times, and thus prefer to schedule how much to produce ahead of delivery on the day-ahead market. This is where most of the physical trade takes place. The day-ahead market is sometimes called the spot market, as the day-ahead price is often used as a strike price to settle financial contracts and determine retail prices. We say that an electricity market is centralized if the day-ahead market uses central unit commitment, i.e. the market operator decides how much should be produced in each plant already the day before delivery. A market with self-commitment in the day-ahead market is decentralized. In this case, the producer can choose by itself how to best produce the committed output. It can also make an agreement with another producer to deliver the committed electricity.

The centralization versus decentralization discussion is not only relevant for the organization of electricity markets. Related issues are relevant for the organization of large firms (Radner, 1992) and also for the discussion between Friedrich von Hayek, Oskar Lange and Abba Lerner about efficiency in socialist and capitalist economies (Mookherje, 2006). Clearly, centralized decision making would be better than decentralized decision making when communication to the central authority is costless, perfectly informative and occurs without delays. Similar idealistic assumptions have been used to motivate centralized day-ahead electricity markets (Ruff 1994, Hogan 1994, Hogan 1995, Sioshansi and Nicholson 2011). But in practice the central authority cannot take for granted that communication is truthful (Melumad and Reichelstein, 1987). One might think that centralization would perform better when there is a greater need for coordination in the organization. But Alonso et al. (2008) show that it could actually be the other way around, because a greater need for coordination means that agents will have incentives to communicate more strategically in a centralized organization.

Untruthful reporting is an issue in centralized electricity markets because uplift-payments give producers incentives to overstate their stated costs (Oren and Ross, 2005). Another issue with electricity markets is that restrictions in the bidding format prevent producers from forwarding all cost-relevant information to the central operator (Sioshansi et al., 2009). Melumad et al. (1992) find that, for generic organizations, decentralization will be optimal, if communication is sufficiently restricted. Also, the centralized communication and clearing process tend to be slower and less flexible. For example, introducing new technologies, e.g. renewables, energy storage and demand response, is complicated in a centralized electricity market. The intra-day market, which takes place between the day-ahead and real-time market, used to be underdeveloped in the US (IEA, 2016; Herrero, 2018). Hence, for many years centralized markets in the US did not give wind-power producers apt incentives to report changes in production conditions and to invest in the optimal forecasting technology. Moreover, dispatches were not updated in a timely and efficient manner. This has now changed in PJM, which has recently introduced intra-day trading.

Intra-day trading is more straightforward in decentralized electricity markets, where producers are free to trade day-ahead commitments with other market participants. Borggrefe and Neuhoff (2011) argue that European intra-day markets have proven to be critical in accommodating large amounts of solar and wind power, because the forecast uncertainty for these technologies is significantly lower during the intra-day market compared to the day-ahead market. It is important that the dispatch can be updated with respect to new forecasts as soon as possible to minimize the cost of rescheduling units (McGarrigle and Leahy, 2015). Intra-day pricing also implies that forecast errors will reduce the profit of renewable producers, which gives them an incentive to improve their forecasts and to trade on new information as soon as possible (Klessman et al. 2008; Karanfil and Li, 2017). Herrero et al. (2018) show that wind-forecast errors in Spain have been reduced by approximately 50% from 2006 to 2014.

An issue with decentralized day-ahead markets is their incompleteness, meaning that producers cannot trade contracts that perfectly match individual non-convexities, indivisibilities and intertemporal costs. On the other hand, this deficiency is potentially eliminated by the rich sequence of markets. In a decentralized market, producers can use intra-day trading to correct non-optimal day-ahead dispatches, for example due to non-convexities and indivisibilities in production. Hence, in principle, a decentralized market should, similar to multi-round auctions, be able to deal with these issues and avoid coordination failures. On the other hand, better possibilities to coordinate and other aspects of the decentralized design increases the risk for collusive outcomes.

IEA (2016) recommends that Europe should develop day-ahead markets with a higher geographical resolution. We share this view. We find that the main problem with many decentralized markets is that the network is considered in a suboptimal way ahead of real-time. The day-ahead market and intra-day trading often neglects network congestion inside large regions/zones. Thus the day-ahead and intra-day dispatch may not be technically feasible, due to congestion inside a zone. This leads to unnecessarily large corrections in the real-time market. This problem can be mitigated by dividing countries into several zones as in Scandinavia, or by introducing flow-based zonal pricing as in Central Western Europe (CWE). Another example is the decentralized market in New Zealand that uses locational marginal (nodal) pricing, i.e. every node of the network has a local market price, which is similar to how networks are represented in the centralized electricity markets in the US.

2 Centralized electricity markets

Centralized day-ahead markets (poolco) apply unit-based/capability-based bidding and central unit commitment. In some ways such markets imitate vertically integrated operations, and they have inherited some procedures from national monopolies and regional power pools that existed before the deregulation (Wilson, 2002). Hence, centralized electricity markets are sometimes called integrated electricity markets. Nowadays, most electricity markets in US use a centralized day-ahead market: New England, PJM, Midwest, New York and California. The old pool in England and Wales and the single electricity market (SEM) in Ireland were European examples of centralized markets. However, Britain and Ireland changed to decentralized markets in 2001 and 2018, respectively. Newbery (2005; 2017) discusses these reforms in detail.

Table 1: Characteristics of centralized and decentralized electricity markets

	Commitment	Nodal pricing	Main energy sources
US Markets			
PJM	Centralized	Yes	Coal, natural gas, nuclear
Texas	Centralized (redesigned in 2010)	Yes	Coal. natural gas, nuclear
Midwest ISO (MISO)	Centralized	Yes	Coal, natural gas, nuclear
California	Centralized (redesigned in 2009)	Yes	Natural gas, renewables, hydro
European & International Markets			
Nord Pool	Decentralized	No (zonal)	Hydro, nuclear, wind
British	Decentralized	No (zonal)	Coal, natural gas, nuclear
Australia	Decentralized	No (regional)	Coal, natural gas, oil

Note: Collected from a variety of sources: see Meeus and Belmans (2007) and Mathiesen (2011) for nodal pricing; see Sioshansi et al. (2008) for commitment in each market; see Australian Energy Update (2016), CAISO (2017), Ofgem (2017) and EIA (2016b) for information on energy sources.

Ideally, producers would forward all cost-related information to the market operator, so that it has full control of all production decisions already in the day-ahead market. Likewise, the system operator of a centralized market would normally take details of the network into account already when clearing the day-ahead market. Centralized markets would normally use nodal pricing, where each node of the network has a local market price. The dispatch is computed by minimizing the total cost of serving demand at every node in the network (or by maximizing gains of trade if demand is elastic), subject to network and production constraints. A network can contain hundreds/thousands of nodes, thus there could be hundreds/thousands of different local prices across the network.

For political reasons, it has proven difficult for regulators in the US (and elsewhere) to charge electricity consumers a price that reflects the nodal price at their location in the transmission network. Those objecting often argue that it would be unfair to charge some customers higher prices due to their location in the network. This type of equity concerns have usually been solved by a regulatory mandate that requires retailers to sell all electricity at the same price within a given service territory. The retailer’s wholesale cost is the quantity-weighted average of the locational prices at all nodes within that territory. From a social-welfare perspective, it is fine that consumers pay in accordance with such an average instead of a local marginal price if consumption anyway is price insensitive.

The main advantage of a centralized day-ahead market is that it makes sure that the day-ahead dispatch is technically feasible and (ideally) cost efficient. Absent new shocks in the system, i.e. outages, demand shocks, transmission failures and variations in the renewable production, no further adjustments would be needed in the real-time market. Considering that some plants can have long ramp-rates, it would be efficient if the dispatch could be determined already the day before delivery.

2.1 Bids provide somewhat distorted information about costs

In the US, producers typically use three-part bids that specify start-up costs, no-load costs and marginal production costs. This restriction is a problem for units with even more complex cost structures (Sioshansi et al., 2009). For example, Combined Cycle Gas Turbine (CCGT) plants typically have saw-tooth shaped marginal costs, i.e. the marginal cost has large variations, up and down, with respect to output, and this variation cannot be captured by a three-part bid. Another example is the cost structure of cascaded hydroelectric systems, where the optimal output of a downstream plant depends on the output of an upstream plant.

A purpose of three-part bids is to separate marginal costs from start-up and no-load costs. The day-ahead dispatch will consider stated start-up and no-load costs, but locational marginal prices are normally set by stated marginal costs. Hence, most centralized markets have a make-whole/uplift payment to ensure that no unit makes a loss. These extra payments mean that the auction is not budget balanced. The day-ahead operator needs to finance these payments, for instance through a mark-up on the price paid by consumers or a fixed fee paid by participants in the day-ahead market. Either way, financing the make-whole/uplift payments will introduce welfare losses, as it will reduce the consumption of consumers or reduce participation in the day-ahead market. This will introduce inefficiencies regardless whether the day-ahead dispatch is socially optimal in itself. In the US markets, make-whole payments are indirectly financed by the market participants. The system operator charges a participation fee from generators based on its market presence, and then allocates make-whole payments to generators in need. In Section 4.1 we discuss alternative ways of financing uplift payments.

Most electricity markets are organized around the idea of marginal pricing, meaning that each location/zone has a market price set by the marginal unit. One advantage is a well-defined market price for all transactions at every specified location. This local price can also be used to define the strike price of financial products, which facilitates hedging. Another advantage is that producers do not have incentives to overstate their costs when they offer electricity in a competitive market. But centralized markets in US also have aspects that make them similar to a discriminatory auction, because make-whole payments are based on stated start-up and no-load costs. Thus two producers that deliver the same amount in the same node at the same time can get different payments. This type of discrimination is one issue with uplift payments. As a consequence, some producers will have incentives to overstate their no-load and start-up costs, even if the market is perfectly competitive. We discuss this in some detail in Section 4.2. Moreover, similar to a pay-as-bid auction, producers would have to estimate by how much they can overstate their costs and still be accepted. Thus profit-maximizing producers will spend more time with preparing their bids, which hurt small firms in particular.

FERC (2014) analysed uplift payments in US and found that yearly average payments for different markets were in the range \$0.30/MWh-\$1.40/MWh. This is relatively small when compared to corresponding average locational marginal prices, which were in the range \$28/MWh-\$57/MWh. FERC (2014) showed that uplifts are concentrated to certain geographic areas: In PJM, 19 plants received more than \$10 million in yearly uplifts payments, in MISO only 2 plants received above \$10 million (FERC, 2014). Large plants were overrepresented among these recipients. A case that has attracted public interest was JP Morgan Venture Energy Corporation, which repeatedly exaggerated its no-load cost by up to twice its value in California's day-ahead market. In the end, they had to pay a total of \$410 million in penalties (Liberopoulos and Andrianesis, 2016).

Liberopoulos and Andrianesis (2016) analyse alternative pricing schemes that have been discussed for markets with non-convex costs. For example, to avoid uplift payments, it would be possible to set market prices sufficiently high so that no plant that is called to produce would make a loss. The semi-Lagrangean relaxation (SLR) (Araoz and Jörnsten, 2011) and the primal-dual (PD) approach (Ruiz et al., 2012) are examples of such pricing methods. This would be closer to the marginal pricing design that is normally preferred for electricity markets. Avoiding uplift payments would also give more well-defined market prices that are useful for hedging. Producers would have less incentive to misstate their costs. In general, many of the pay-as-bid related issues of centralized electricity markets could be avoided, including distorted information about start-up and no-load costs. On the other hand, there are also advantages with pay-as-bid pricing. For example, and as will be discussed in more detail later in this paper, one advantage is that it is less likely to get collusive outcomes in an electricity market with pay-as-bid pricing.

2.2 Centralized markets are inflexible

A problem with centralized markets is inflexibility. Under centralized unit commitment in the day-ahead market, each unit has an individual commitment and a tailor-made contract, which is difficult to trade in the intra-day market. Centralized markets sometimes even use sanctions and penalties to deter producers from making changes in their day-ahead dispatch (Wilson, 2002). This has recently improved, for example in PJM, but it used to be the case that producers had to wait until the real-time market to be able to make adjustments in the day-ahead dispatch. Thus, a centralized market has, or used to have, a slow response to shocks that occur after the day-ahead market has closed, such as changes in the prognosis of wind-power output, unplanned outages, disturbances in the network etc. Missing intra-day prices is a problem for producers that want to make optimal updates of their dispatch (Helman et al., 2008; Herrero et al., 2016), especially for plants with long ramp-rates that schedule production well in advance of the real-time market. There is a similar problem for producers with complicated costs that are not well-represented by three-part bids. A producer cannot correct its day-ahead dispatch until the real-time market if there is no intra-day market.

Another source of inflexibility is the time and money required to develop new bidding formats that match new technologies, such as energy storage and demand response. In the US, demand response is aggregated by authorized Curtailment Service Providers (CSP) or demand response providers, who submit bids to the electricity market on behalf of clients. Before such demand-response capacity can be used in the day-ahead market, there is a bureaucratic process through which this capacity has to be verified. Often, the demand response should be able to follow dispatch orders from the centralized day-ahead market.

2.3 Centralized markets are opaque and hard to scale up

The purpose of including start-up costs, no-load costs and other dynamic costs in the bidding protocol is to optimize the day-ahead dispatch. But these intertemporal costs and constraints make it impossible to separate the clearing of adjacent delivery periods. In practice, this makes it computationally challenging to clear the centralized day-ahead market in a quick and transparent way. For example, ERCOT, the system operator in Texas, has thousands of computer servers to run its systems (Cramton, 2017). Normally it is not possible to find the optimal dispatch in that case. Instead, one has to settle for an approximately optimal dispatch through an iterative procedure. The number of iterations is bounded because the day-ahead market must be cleared within a limited time frame, e.g. 5-60 minutes. For some units the dispatch can vary greatly from one iteration to the next in the clearing process, thus making it somewhat arbitrary whether the unit is dispatched or not, especially if the unit is on the margin of being accepted. After such a clearing, it may be difficult for a market participant to understand why an offer was rejected/accepted. In this sense, a centralized day-ahead market is opaque and somewhat of a black box.

Many electricity markets, such as MISO and PJM make use of mixed-integer algorithms, and such clearing algorithms are NP-hard (Streiffert et. al, 2005). In such cases, memory requirements and run-times could grow exponentially with the size of the problem, such as the number of production units or the number of delivery periods that are to be cleared simultaneously.

As the scale of the system increases, it becomes harder to optimize everything simultaneously. It is still possible to require that the clearing iterations must stop within a given time period, such as 30 minutes. But a larger problem to solve within a given computation time, would reasonably mean that the accuracy and efficiency of the reported dispatch should go down. Scalability of the clearing algorithm is important, because both Europe and the US are integrating markets across country and state borders. Similarly, the clearing procedure becomes more challenging for centralized markets with shorter delivery periods, because this increases the number of interrelated delivery periods per day.

Fortunately, at the same time as markets become larger and more complex to clear, the computer performance, and also the performance of mixed-integer algorithms (Streiffert et al, 2005) has improved dramatically. Such advances have contributed to PJM's recent introduction of 5-minute delivery periods. Even so, running a centralized day-ahead market still represents a very computer-intensive problem.

2.4 Separated transmission ownership and system operation

In centralized systems, the system operator is normally involved in the day-ahead market and sometimes also in capacity markets, which take place long before delivery. This would be an issue if these market operations would influence its profit, such congestion rents. To avoid this problem, system operators in US do normally not own any transmission lines or any reserve capacity. Hence, they are referred to as independent system operators (ISOs). However, even if transmission ownership and system operations are separated, it should still be possible for owners of the transmission grid to influence their payoff by making strategic statements of the capacity and status of the grid. As far as we know, this is an issue which has not been sufficiently analysed by the academic literature. The role of system operators and how they should be regulated is further discussed by Pollitt (2008; 2012), Chawla and Pollitt (2013), Anaya and Pollitt (2017), and Stern (2013; 2015).

2.5 Cost-based electricity market

A more invasive form of centralization is when the market operator does not trust producers to make their own bids. In cost-based electricity markets, the operator studies production plants in detail and uses audited cost information to determine prices and dispatches. This type of market regulation is mainly used in hydro-dominated countries in Latin America, such as Bolivia, Brazil, Chile, Peru, and countries in Central America (Hammons et al., 2002). A similar regulation is also used in the US when local market power is demonstrated to be sufficiently high (Munoz et al., 2018) and in the redispatch in some European electricity markets (Grimm et al., 2016).

A cost-based market design does not necessarily eliminate the ability of producers to exercise market power. Wolak (2003b) notes that unless properly monitored and regulated, producers can, through transactions with affiliate companies, make fuel costs and other input costs correspond to whatever level that they would like to bid, so that a cost-based market becomes equivalent to a bid-based market. Such manipulation of input prices was for example observed during California's electricity crisis (Wolak, 2003a). To avoid this, more regulation and surveillance is needed in cost-based electricity markets compared to bid-based markets. Still, Wolak (2003a) argues that a cost-based dispatch can be the best solution for many countries in Latin America, because it is also very expensive to set up a bid-based spot market.

Munoz et al. (2018) discuss additional problems with cost-based electricity markets. For example, producers will invest too little in base load and excessively in peak power to push up the price, if investment is unregulated. Moreover, restrictions on the number of unit start-ups due to thermal/maintenance constraints introduce an opportunity cost, i.e. the payoff that the generator would earn if a start-up was delayed. Related issues are introduced by take-or-pay contracts for gas, which are used in a large number of countries (Munoz et al., 2018). These contracts specify both a price and a quantity at the time of delivery, and a penalty for any deviation from the contracted volume. This penalty can also introduce an opportunity cost. Relatedly, Holmberg and Wolak (2018) argue that daily natural gas prices can have large uncertainties due to local congestion and local storage constraints in pipelines. Moreover, the owner of a thermal plant has private information about the efficiency of its plant, which depends on the ambient temperature, and how the plant is maintained and operated. Normally, it would go far beyond the responsibility of a market/system operator to keep track of all these details and to estimate any opportunity costs that can occur. This means that cost-based electricity markets will result in somewhat inefficient dispatches.

3 Decentralized electricity markets

European markets are decentralized markets in the sense of allowing producers to use self-dispatch in the day-ahead market. This means that producers can choose how to deliver the committed energy at the agreed location. They are also free to pay another producer to deliver the energy instead. This is sometimes called portfolio-based bidding.

Decentralized markets acknowledge that it is necessary to have a system operator with exclusive authority to manage the power system in real-time, but its authority to intervene ahead of delivery is often limited to day-ahead scheduling of the transmission network. One purpose is to minimize the operator's monopoly influence on electricity markets (Wilson, 2002). For example, there are studies showing that if a system operator owns parts of the network, then it has incentives to set transmission capacities that increase rents and reduce counter-trading costs from the network (Bjørndal et al., 2003; Glachant and Pignon, 2005).

Still, European system operators have often been directly or indirectly involved in the organization of the day-ahead and intra-day markets. But some markets are more decentralized. The NETA reform in the UK originally left it to the market to sort out any trading ahead of real-time. New Zealand is also very decentralized in that all trading before the real-time market is financial. Decentralized markets are therefore sometimes referred to as exchange-based, unbundled or bilateral markets.

As system operators are less active in decentralized markets, the separation of transmission ownership and system operations is less of an issue. In Europe, the system operator often owns transmission lines in accordance with the ITSO (Independent Transmission System Operator) model. UK is an exception, it has recently decided to separate ownership of the grid from system operations.

3.1 Decentralized markets are flexible

The electricity markets in Europe are divided into zones, and there is one spot (day-ahead) price per zone. Most European countries have one zone per country, but some countries have several zones. One advantage with zonal pricing is that delivering electricity in a zone becomes a standardized product that can be traded with other market participants in the secondary market, such as the intra-day market. This makes it straightforward for producers to frequently update their dispatch when new information arrives about unplanned outages, renewable output, the demand level, and network shocks. Moreover, intra-day prices are also frequently updated, which gives producers the right price signal when making corrections in the dispatch.

Producers can use the flexibility of decentralized markets to manage indivisibilities, non-convexities and economies of scope. Once producers have a good estimate of the price for each hour, it is straightforward to take intertemporal costs into account and to choose an optimal output for each hour. Furthermore, separate future prices for each delivery hour would facilitate the price discovery process. Indivisibilities and non-convexities are somewhat harder to manage as the output would have to be coordinated with the output of other plants, which might be owned by another producer. For example, if there are two identical plants with the same marginal, no-load and start-up costs, and only one of the plants is needed, then producers need to coordinate their decisions so that exactly one plant is started. Still, in case producers misestimate prices or make coordination mistakes, they can correct the dispatch in the intra-day market. In particular large producers would be able to work around some non-convexity/indivisibility issues in decentralized markets by making adjustments in their internal production schedules.

One advantage of a decentralized design is a flexible market organisation that would also work for new technologies, such as demand response and energy storage. As long as forward, day-ahead and intra-day markets provide adequate prices for each delivery hour, owners of energy storages can, on their own, decide when to buy and sell electricity, and consumers with demand response can decide how to shift their load. This could be done manually or automatically. A retailer will bid on behalf of its aggregated consumers. In a decentralized electricity market, the retailer can predict the aggregated demand response of its customers from historical data. Hence, demand response can be introduced without involving a Curtailment Service Provider that verifies the capacity of the demand response and/or takes control of the demand response. Moreover, demand response can be used without introducing new bidding formats. In this way, decentralized day-ahead markets are more flexible and less bureaucratic than centralized markets. A long-run advantage of letting the market sort out the organisation of day-ahead and intra-day trading is that this should lead to a more dynamic and innovative organisation of trading.

Currently, many European markets have continuous intra-day trading. This makes it problematic to price transmission capacity between zones (Neuhoff et al., 2016). In practice, transmission capacity is allocated free of charge on a first-come, first-serve basis in the intra-day market. Hence, the scarcity value of transmission capacity is collected by quick traders instead of the network owner, which would be more efficient. Frequent intra-day auctions, as in Spain, would price transmission capacity in a more efficient way. Another challenge with continuous intra-day trading is that it encourages automatized (algorithmic), high-frequency trading. This means that the number of orders will surge, which can be overwhelming for a continuous market. Trading in a finite number of auctions (frequent batch auctions), is more reliable, and less likely to have breakdowns. Moreover, the possibility of high-frequency trading means that traders will compete by increasing their speed, and it is controversial whether investment into such activities is beneficial for society (Budish et al., 2015).

Letting producers sort out issues with economies of scope and coordination by way of forward, day-ahead and intra-day markets is related to the multiple period auctions typically used for trading interrelated items, such as spectrum licenses for neighbouring regions (Ausubel, 2004; Ausubel and Cramton, 2004; Milgrom, 2000). During the late 1990s, the California Power Exchange considered implementing a multi-round auction in the day-ahead market, but the idea was never realized. Wilson (2001) outlines design details for such an iterative power exchange. Moreover, day-ahead markets are repeated daily, with small variations between days. Thus producers have experience from previous auctions that will help them to predict prices and to get coordination approximately right already in the day-ahead market (Wilson, 2002).

3.2 Decentralized markets have inefficiencies, but facilitates hedging and clearing

The decentralized markets are typically energy-only markets, where producers are paid (and consumers pay) a local price in their zone. This means that the market is budget balanced. Moreover, it is easier for producers to hedge their profits if transfer prices are at zonal spot prices, which in turn can be used as strike prices for financial contracts. In the long-run, more straightforward and effective hedging should be beneficial for investments and availability of plants.

Another advantage of decentralized markets is the decoupling of delivery periods, so that the day-ahead market is transparent and easy to clear. Decentralization implies that each individual producer needs to estimate prices and determine its optimal dispatch contingent on those estimates. Potential problems of decentralized markets are the transaction costs associated with production planning and intra-day trading. Such costs arise also for retailers that represent consumers with demand response.

A producer with non-convexities such as decreasing marginal production costs, would sometimes need to offer its supply at a price above its marginal cost to avoid a loss. Such mark-ups generate welfare losses, as the mark-ups reduce demand. These losses are likely to be higher than in a centralized market. But, as discussed in Section 4, it depends on how up-lift payments are financed in the centralized market.

3.3 Block orders and complex bids

The Nordic and other European countries allow market participants to use block orders (Meeus et al., 2009). A block bid is a fill-or-kill order, it cannot be partly accepted. Block-bids assist in managing indivisibilities in production plants. They can also be used to manage non-convexities, for example by fixing the output at the optimal production level of a plant. In the Nordic countries, a block bid can span several hours. The bid is only accepted if the average price during those hours is sufficiently high. Thus producers can use block bids to manage economies of scope, no-load costs and start-up costs. Block orders replicate some aspects of centralized markets, but there are also crucial differences. First, block orders are more flexible. If a producer wants to increase its output for one hour in the block, it can simply sell more for that hour in the intra-day market (independent of other hours in the block). Second, the offer price of a block should consider all costs, including no-load and start-up costs that need to be covered if the block is accepted. This avoids the need for uplift payments, and there are no issues with budget imbalance and discriminatory pricing.

Block orders share with centralized markets the problem of intertemporal dispatch across hours, which renders the market opaque and hard to scale up. To reduce the computational complexity one could put restrictions on block-orders that ease market clearing, but restrict preferences for market participants (Park and Rothkopf, 2005; Xia et al., 2005). Meeus et al. (2009) argue that it is mainly the number of block types (composition) that affect the computation time, while the number of blocks and their size is less of an issue.

Spain encourages producers to make unit-based, multi-part bids as in a centralized market (Neuhoff et al., 2015). Reguant (2014) refer to such bids as complex bids. Spain is decentralized in other aspects. One could say that Spain allows for self-dispatch in the sense that imbalances are settled for aggregated groups of a producer's units (Neuhoff et al., 2015), which is similar to portfolio-based bidding.

3.4 Inefficiencies due to zonal pricing

In our view, the main problem associated with decentralized markets is that zones tend to be too large. This means that intra-zonal constraints are not properly accounted for in the day-ahead and intra-day markets. But when electricity is to be delivered in real-time, all relevant technological constraints must be considered. This makes the real-time adjustment unnecessarily large. It would be more efficient to get the dispatch right earlier on when more plants are able to adjust their output.

Another problem with zonal pricing is that different representations of the transmission constraints in the day-ahead and real-time market result in partly different prices in the two markets. This gives producers an arbitrage opportunity, which increases real-time trading even more. As shown by Harvey and Hogan (2000a,b), Dijk and Willems (2011), Holmberg and Lazarczyk (2015), Hesamzadeh et al. (2018) and Sarfati et al. (2018a,b), a producer in an export-constrained node can increase its profit by selling more in the day-ahead market at the zonal price and then buy back power at a lower local (discriminatory) price in the real-time market. This kind of bidding behaviour is referred to as the increase-decrease (inc-dec) game. As explained by Alaywan et al. (2004) this game contributed to the electricity crisis in California. According to Neuhoff et al. (2011), there are also problems with the inc-dec game in the British electricity market.

California and other markets in US switched from zonal to nodal pricing to avoid the inc-dec game (Alaywan et al., 2004). In Europe, the problem with arbitrage gaming can be mitigated by reducing the size of zones. For example, Denmark, Norway and Sweden have at least two zones per country. New Zealand is an example of a decentralized day-ahead market that uses nodal pricing. EU is advocating flow-based zonal pricing (van den Bergh et al., 2016), which has been implemented in Central Western Europe (CWE). In an approximate way, this approach considers the most critical congested lines inside a zone, and still has one price per zone. This zonal approach should mean that it will be sufficient with small real-time adjustments of the dispatch, even if the zones are large. Simulations by Sarfati et al. (2019) confirm that flow-based pricing can mitigate the inc-dec game and reduce welfare losses in a zonal market. Hesamzadeh et al. (2018) show that the inc-dec game can also be mitigated by a change in the design of the real-time market.

The Australian market applies an alternative form of zonal pricing, which is sometimes referred to as regional pricing. In this market, the day-ahead dispatch takes all network constraints into account. Thus the day-ahead dispatch would be as efficient as nodal pricing if all producers would make offers in accordance with their costs. Unfortunately, all producers do not have incentives to state their costs correctly, even if the market is competitive. The price in each region is set by the nodal price in a reference node. This means that for an import constrained node, where the local price should be high, the market operator can accept units with a marginal cost above the reference price. Still units in that node are only paid the reference price, so such a unit is said to be *constrained on* (Biggar and Hesamzadeh, 2014). Obviously, a firm will do its best to avoid a situation where it makes a loss. Thus, units that are at risk of being constrained on will overstate their cost. In import-constrained nodes producers would sometimes need to raise the offer price all the way up to the price cap to make sure that the auction accepts an offer from a competitor instead. In the Australian electricity market, this is known as disorderly bidding (Biggar and Hesamzadeh, 2014). Similarly, in export constrained nodes, production units with a marginal cost below the reference price are at risk of being constrained off, i.e. offers are rejected even if they are willing to produce at the reference price. Such units sometimes undercut each other down to the price floor to make sure that the units are accepted and paid the reference price. Similar to the European zonal designs, the problem with disorderly bidding can be mitigated by reducing the size of zones.

4 Market power and its interaction with market designs and non-convexities

Decentralized markets tend to rely on competition and profit maximization to make producers behave efficiently. Centralized markets use relatively more of command and control to impose producers to make efficient decisions. But also in such markets, performance is improved by better competition. For example, producers have less possibilities to overstate no-load and start-up costs in a competitive market. But electricity markets are normally oligopoly markets with imperfect competition. In this section, we will discuss market power and how it interacts with the market design and non-convexities.

In practice, exercise of market power in electricity markets can be non-problematic at some times and excessive at other times. The latter occurs when only a few producers compete for the marginal load. The switch from non-problematic to problematic market power is more pronounced in electricity markets compared to most other markets. There are two main reasons. First, ownership of production plants has often been concentrated to a few big producers. Second, electricity is expensive to store (Borenstein et al., 1999).

We start this section with a simple example of how firms in theory would exercise market power under linear and non-linear prices. We note that if consumers pay non-linear tariffs, where a lump-sum fee is used to cover the uplift payments in centralized markets, then a monopoly producer could potentially use its multi-part bid to extract all rents from consumer, similar to the Disneyland dilemma (Oi, 1973). While efficient, the outcome leads to an inequitable distribution of surplus. Under linear prices, allocations are inefficient, but the distribution of surplus is less uneven. Hence, there is a trade-off between efficiency and rent extraction in the design of electricity markets. We then discuss game-theoretic models of electricity markets with non-convexities and/or indivisibilities and collusive outcomes. Finally, the section discusses how hedging/contracting, which mitigates the use of market power, depends on how the market design manages congestion. In Tables 2 and 3, we summarize some issues and potential remedies for centralized and decentralized day-ahead markets, respectively.

4.1 The deadweight loss and rents

In this subsection, we explain how producers in imperfectly competitive electricity markets can drive up the consumers' cost of electricity by an exercise of market power. This ability arises because firms are free to submit any offer curve, or at least up to the bid cap, independent of their cost of generating the supplied electricity. Market power is limited by consumers' willingness to pay for electricity and the offers submitted by competing firms. Bids are stated costs, such as no-load, start-up and marginal costs. There is nothing preventing generation owners from exaggerating their costs to extract additional rent from consumers.

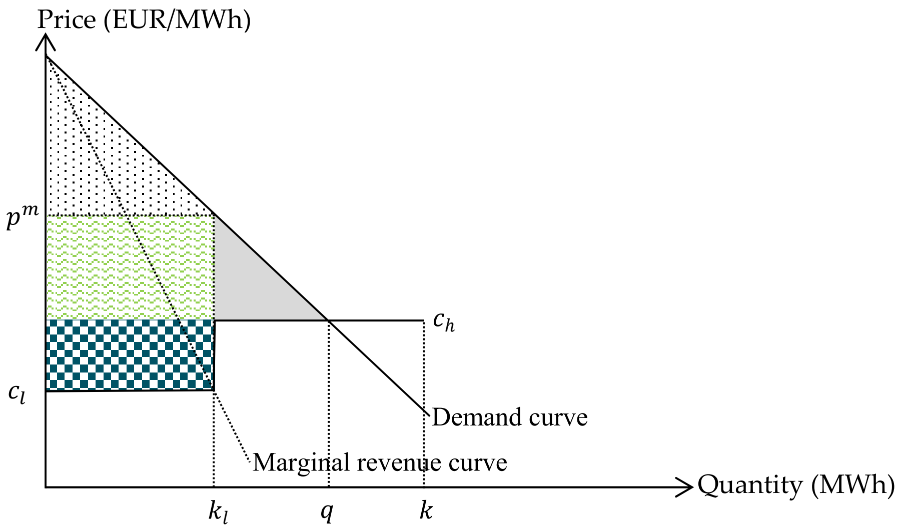

Figure 1. Illustration of rents and efficiency.

In Figure 1, production in MWh is on the horizontal axis, and prices in EUR/MWh are on the vertical. As an illustration, consider a monopoly firm that owns two generation units, a base-load unit with variable unit cost c_l and capacity k_l, and a peak-load unit with variable unit cost c_h and capacity $k_h = k - k_l$. In this notation, k is the firm's total production capacity. The firm's short-term marginal production cost curve is the solid stepped function in the figure. Assume also that base-load capacity has a start-up cost $C_l = (c_h - c_l)k_l > 0$. This is the chequered area in the figure. The peak-load plant has no start-up cost: $C_h = 0$. The inverse electricity demand curve facing the firm is drawn in the figure as a linearly decreasing function of quantity. This demand equals total demand minus the supply of all other firms, the competitive fringe. The competitive solution is found where the inverse demand curve intersects the short-term marginal production cost, at q. Hence, the firm sells q units at price c_h in competitive equilibrium. The revenue generated in the market precisely covers the start-up costs of each separate unit.

However, competitive prices are not going to occur in a market where firms exercise market power. Supplying more to the wholesale market leads to a reduction in the price. For an arbitrary level of output, the marginal revenue shows by how revenue will increase by selling an additional MWh in the wholesale market. It is equal to the market-clearing price at that quantity minus the product of the quantity and the marginal price decrease. The marginal revenue curve is identified in Figure 1 as the linearly decreasing dotted line. A firm with market power takes the price effect into account when deciding how much to supply to the wholesale market. The profit maximizing quantity for the firm is found at the point at which the marginal cost curve intersects the marginal production cost curve, at k_l units in the figure. The maximal price the firm can charge and still be able to sell all k_l units is p^m, which is then the market-clearing price of electricity. The marginal revenue is insufficient to cover the variable unit cost of the peak unit. Hence, a firm that exercises market power will not activate the peak unit in the case we have depicted. But the marginal revenue is sufficiently high to cover the unit variable cost of the base-load unit. The deadweight loss of forsaking the peak unit is equal to the shaded grey triangle in Figure 1, because for all units between k_l and q, the unit variable cost of producing electricity is below the price consumers are willing to pay for it. Summing up the difference across all these units gives the deadweight loss. Despite this inefficiency, consumers still earn a positive net benefit from purchasing electricity. The net consumer surplus under market power is represented by the dotted area in the figure. It represents the difference between what consumers are willing to pay for electricity and the price p^m they actually pay for the k_l MWh electricity they consume in equilibrium. The waved area is the producer's associated gain on the base load unit from increasing the price from c_h to p^m.

The deadweight loss and mark-ups are lower when the market is more competitive. Market concentration in wholesale electricity markets as measured by the Herfindahl-Hirschman Index (HHI) is typically in the range 1000-2000, both in Europe (Newbery, 2009) and U.S. (Bushnell et al., 2008). This degree of market concentration corresponds to a market with 5-10 symmetric suppliers. For markets with 10 (uncontracted) suppliers, Holmberg and Newbery (2010) estimate that the deadweight-loss is below 1% of the total producer profits.

The stylized example could illustrate the exercise of market power in both decentralized and centralized systems. As of today, our understanding is that uplift payments to producers in US are financed by a membership fee, mainly from producers (PJM, 2009). The fee is individual and partly proportional to the turnover of a member. Such a fee corresponds to an increase in the marginal cost of a producer, which will be passed through to consumers by an increase in the price. Thus in the end consumers will pay a price that covers start-up and no-load costs, which is similar to a decentralized market. But one could think of an alternative centralized design, where consumers pay a non-linear price for electricity, a lump-sum fee and a per-unit charge. If the lump-sum fee is used to cover uplift payments to producers, then this would influence efficiency and rents of a centralized design in an interesting way.

With non-linear pricing in a centralized system, things will be worse for the consumer because now the generation owner not only charges a price for the electricity that is produced, but also has an opportunity to claim reimbursement for its start-up costs. And because the system operator takes reported costs at face value, the owner has an incentive to exaggerate those, especially if it is a monopolist. Return to the example in Figure 1, and assume that the generation owner bids in its base-load capacity k_l at a claimed unit variable cost equal to p^m and claims a start-up cost of its base-load plant equal to C_l plus $(p^m - c_h)k_l$, which is equal to the waved area in the figure, plus the net consumer surplus, the dotted area. Assume also that it bids in the peak-load unit at a prohibitively high price. Then the system operator has no choice but to accept the baseload offer. The market-clearing price is p^m as before, but now the system operator also has to make additional payments to cover the claimed start-up cost of the base-load unit, a cost which eventually is passed on to consumers. In this outcome, the deadweight loss is still given by the dark triangle, but now the generation owner is able to extract the entire consumer surplus through the additional "uplift" payment.

The first general lesson from this example is that a centralized market with non-linear prices for consumers leads to more rent extraction from consumers by generation owners. However, the story does not necessarily end there. The firm also has the option of bidding in its peak-load capacity. To sell more than k_l MWh electricity, the firm must reduce its price from p^m. For instance, the firm could reduce it all the way down to c_h and sell q MWh. The benefit of doing this is that it could now extract the deadweight loss by claiming a start-up cost of the peak unit equal to that dark triangle in the figure. The downside to this is that the firm must reduce the claimed start-up cost of the base-load unit to avoid the system operator replacing the base-load unit by the peak-load unit. Hence, it might not be optimal for the generation owner to reduce prices all the way down to c_h, but it will be optimal to sell more than k_l units in a centralized market with non-linear pricing. Even so, consumers are unlikely to benefit from such an output expansion because firms will increase their claimed start-up costs correspondingly.

The second general lesson from this example is that a centralized market where consumers pay a non-linear price is more efficient (entails a smaller deadweight loss) compared to the decentralized market if firms have market power because of the possibility of bidding in the different units at different prices. The design choice is an example of the classical trade-off between efficiency and rent extraction that is endemic to models of asymmetric information; see for example Laffont and Tirole (1993). This trade-off depends on the competitiveness of the electricity market. In a market with linear prices, it is less profitable to withhold production to increase the price if there are more competitors in the market. In a centralized market with non-linear prices, it is more difficult to exaggerate costs to extract rent if there are more competitors. Therefore, the efficiency-rent trade-off probably is less important in a competitive wholesale electricity market.

In economic studies of electricity consumers, it has sometimes been argued that non-linear pricing could be too complicated to understand for electricity consumers. In practice their response may not be consistent with economic theory. For example, the empirical studies by Borenstein (2009) and Ito (2014) show that for highly non-linear tariffs in California, many consumers respond to average prices rather than marginal prices. This seems to suggest that our discussion above on the trade-off between efficiency and rent extraction may not be valid in practice. On the other hand, as argued by Borenstein and Bushnell (2018), it should be easier for consumers to separate a recurring fixed charge and a marginal price, as in our examples above, in comparison to the highly non-linear volume-based charges in California. Also, Wolak (2016) find that for a related industry, water, household's consumption approximately responds to marginal prices, even if prices are non-linear.

4.2 Game-theoretic evaluations of market designs

Market designs are normally evaluated by comparing market equilibrium outcomes. Competitive markets are often modelled by Walrasian equilibria, where producers are assumed to be small and costs are assumed to be convex (Arrow and Hahn 1971; Takayama 1985; Varian 1992; Mas-Colell et al. 1995). This is a convenient approximation, but it is not quite true for electricity markets. Scarf (1990, 1994) and Villar (2012) extend the Walrasian equilibrium to consider non-convexities. Bonnisseau and Medecin (2001) prove the existence of such an equilibrium in a market with non-convexities and externalities. Their results are later extended by Fuentes (2011).

Competition is normally imperfect in electricity markets. Such circumstances are often evaluated by game theory. In this case it is assumed that each producer chooses offers that maximize its expected profit, given strategies chosen by its competitors. One can then solve for a Nash equilibrium (NE) where all producers maximize their profits simultaneously. It is an equilibrium in the sense that no producer has incentives to unilaterally deviate from this outcome.

A NE is called a pure-strategy NE if each producer will use the same strategy for identical market conditions, while producers would use randomized strategies in a mixed-strategy NE. In accordance with the purification theorem (Harsanyi, 1973), and as shown by Holmberg and Wolak (2018), mixed-strategy NE is equivalent to circumstances where each firm observes small random variations in its costs, which are not observable by competitors, and where the optimal offer of the firm is very sensitive to small variations in its own costs.

In practice, it will be difficult for market participants to find the equilibrium right away, but if the auction is repeated many times, then the market should find an equilibrium in the end. Empirical studies of the wholesale electricity market in Texas (ERCOT) show that offers of the two to three largest producers in this market roughly match the optimality conditions of a Nash equilibrium, while the fit is worse for small producers (Sioshansi and Oren, 2007; Hortaçsu and Puller, 2008). Wolak (2007) shows that observed offers, both from small and large firms, in Australia are consistent with the market being in a Nash equilibrium.

Sioshansi and Nicholson (2011) use a game-theoretic model to compare the bidding behaviour in centralized and decentralized markets. They consider a symmetric duopoly, where each producer has one plant with a start-up cost and a flat marginal cost. They assume that producers must make a flat offer per plant in its statement of the marginal cost. Producers compete to serve a load that is certain, common knowledge, and insensitive to price changes. They then compare the outcome for a centralized market (with two-part offers and uplift payments) and the decentralized market. Flat offers give producers an incentive to undercut each other. In the low-demand (non-pivotal) case, the production capacity of each plant is sufficient to serve demand. In this case, producers will, similar to a Bertrand game, undercut each other until the profit is zero. This will change in the pivotal case, where both plants are needed to serve demand. In that case, equilibrium mark-ups will be positive and, similar to a Bertrand-Edgeworth game, both markets will have a mixed-strategy NE where producers trying to undercut each other will introduce volatile bidding. In this equilibrium, prices will vary unpredictably even if the underlying market fundamentals are stable. For this equilibrium, expected profits are the same in both auctions. Fabra et al. (2006) have proven a similar revenue-equivalence result for uniform-price and discriminatory auctions without start-up costs. Wang et al. (2012), Wang (2013) and Andrianesis et al. (2013a,b) extend some of the results in Sioshansi and Nicholson (2011) to asymmetric producers and to alternative designs of uplift payments.

Production costs are to a large extent common knowledge, but each supplier also has some private information, see for example the discussion about cost-based markets in Section 2.5. Holmberg and Wolak (2018) consider cases where the cost information of producers is affiliated, i.e. if the cost of one producer increases, then it (weakly) increases the probability that its competitor has a high cost relative to the probability that its competitor has a low cost. Holmberg and Wolak (2018) show that a pay-as-bid auction is not an optimal design to deal with cost uncertainties of this type. An auction where producers are paid the marginal price is better at dealing with information asymmetries. This suggests that decentralized markets are better at dealing with asymmetric information compared to centralized markets with uplift payments.

In the decentralized market, the randomized bidding behaviour that is found by Sioshansi and Nicholson (2011), and in related studies by Fabra et al. (2006), is driven by flat offers. In a decentralized market, offers would normally not be flat unless the bidding format explicitly requires offers to be flat (Ausubel et al., 2014; Holmberg and Wolak, 2018; Anderson and Holmberg, 2018). But in a centralized market with uplifts, total offers – including start-up costs etc. – should, at least in theory, be fairly flat even if it is not required by the market design. The reason is that producers will have incentives to bid as under discriminatory pricing. A profit-maximizing producer would overstate the costs for each unit, so that (in theory), all accepted offers would be close to the margin of being accepted. Thus the pay-as-bid aspect of the up-lift payments encourages producers to make offers that are very elastic with respect to the price, which gives volatile bidding. Anderson et al. (2013) show that this type of price instability can introduce significant efficiency losses in auctions because the producer with the lowest cost may not always have the highest output when prices and bids vary in a randomized manner. Results in Holmberg and Wolak (2018) and Anderson and Holmberg (2018) suggest that inefficiencies caused by volatility can be reduced if the market operator restricts offers to have a shape/slope that is similar to the shape/slope of the marginal cost. As an example, if each plant has a constant marginal cost independent of output, then it should be beneficial to restrict the number of steps in the offer stack of a producer so that it is equal to the number of plants. In a centralized market, one could instead restrict each producer to make one offer per plant as in Colombia (Wolak, 2009).

4.3 Collusive outcomes in decentralized markets

We have mentioned some disadvantages of uplift payments and discriminatory pricing, but there are also advantages. One advantage is that each offer becomes price-setting (influences the payoff from its associated plant). This gives producers less degrees of freedom when they prepare their offers, and this reduces the set of equilibrium outcomes. This means that the worst equilibrium outcomes can be avoided in a centralized market, which may not be the case in a decentralized market. For example, in the case where producers are pivotal with certainty, Sioshansi and Nicholson (2011) find that the decentralized market has a high-price, pure-strategy NE, in addition to the mixed-strategy Nash equilibrium. In the high-price equilibrium, one producer sets the price at the price cap and the other producer bids sufficiently low to avoid being undercut. For this outcome, the decentralized auction will be significantly worse for consumers than the centralized auction. Previously, von der Fehr and Harbord (1993) have shown that there is a similar high-price equilibrium in the uniform-price auction, and when producers select this equilibrium in a uniform-price auction, then this auction is much worse for consumers compared to a discriminatory auction. The high-price equilibrium could also lead to inefficient production.

The high-price equilibrium has been observed in the capacity market of New York State's electricity market, which is dominated by one supplier and where the demand variation is small (Schwenen, 2015). In theory, the high-price equilibrium would only exist if producers are 100% certain to be pivotal, which is rarely the case in most electricity markets. Bidding in electricity spot markets (Sioshansi and Oren, 2007; Hortaçsu and Puller, 2008; Wolak, 2007) and experimental results by Brandts et al. (2014) is inconsistent with this type of extreme pure-strategy NE, and closer to the equilibria where producers are somewhat uncertain of their pivotal status. In this case, we predict that auctions would be revenue equivalent, at least for the simplified settings considered by Fabra et al. (2006) and Sioshansi and Nicholson (2011). Still, one concern is that measures that help producers to coordinate start-ups and non-convexities in decentralized markets, such as increased transparency and iterative trading, could also help producers to coordinate prices (von der Fehr, 2013). Fabra (2003) shows that producers have stronger incentives to collude in a uniform-price auction compared to a pay-as-bid auction, which speaks in favour of centralized markets with uplift payments.

Mookherjee and Tsumagari (2004) consider the problem of centralization versus decentralization when producers have the option to collude to increase their profit. They assume that the unit variable costs is private information and unobservable to outsiders. Start-up costs are known (and set equal to zero). A key finding of their paper is that since the electricity produced in the two units are substitutes for one another, centralization is a more efficient market design.

4.4 Contracting in centralized and decentralized markets

Financial contracts are useful to hedge the risk of market participants. But it is also well-known from Allaz & Vila (1992), Newbery (1998), Green (1999), Wolak (2000; 2007), Cramton (2004), and Holmberg & Willems (2015) that contracting reduces a producer's incentive to exercise market power. The intuition is that a firm that has hedged a large fraction of its output gains less from increasing the day-ahead price.

The old California design of the electricity market prevented large utilities from entering forward positions and this contributed to the crisis in 2000-2001. Bushnell et al. (2014) find that if the east-coast markets (e.g. PJM or New England) would have prevented contracting in a similar way, it would have increased production costs by 45 percent. Therefore, it is interesting to study how different market designs and the organisation of retailers influence the contracting incentives.

In Europe, retail and distribution are separated. This is referred to as the retail competition model (Biggar and Hesamzadeh, 2014). This differs from the US, where distribution and retail are often bundled into regulated Load Service Entities (LSEs), as in the wholesale competition model (Biggar and Hesamzadeh, 2014). Retailers in Europe and corresponding Load Entity Services (LES) in the US offer electricity at a fixed price to some consumers. This exposes them to a considerable risk. Hence, they have incentives to buy electricity in the forward market. Similarly, producers have an incentive to sell electricity in the forward market to hedge their profits. This mutual interest to contract will lower mark-ups.

At least in theory, competition between retailers should reduce mark-ups and also help consumers find contracts that match their risk preferences. But it is not self-evident that better matching will increase or decrease contracting of consumers. Large LSEs in US would have significant buyer power, and this could stimulate contracting and reduce mark-ups in the spot market, as shown by Anderson and Hu (2008) and Ruddell et al. (2018). On the other hand, retailers in Europe typically have thin margins, which make them risk averse and keen to hedge (Powell, 1993).

Centralized electricity markets tend to have nodal pricing. One concern is that the multiplicity of prices to hedge will undermine liquidity in forward markets. In the US there is sufficient liquidity in trading hubs and also the liquidity in the US has been supported by auctions of financial contracts (Neuhoff and Boyd, 2011).

Tangerås and Wolak (2017) show that when there is imperfect competition, then contracting is influenced by how the market design deals with network congestion. They demonstrate that due to improved contracting incentives for producers, it is an advantage that consumers in the US pay a uniform quantity-weighted price. They show that such a design improves market performance in imperfectly competitive wholesale electricity markets substantially beyond the level that would exist if there were location-specific retail prices. Hence, there is not necessarily a trade-off between policies to address equity considerations and market efficiency in electricity markets.

Almost all large electricity companies are vertically integrated between production and retailing, which tends to improve short-term wholesale market performance because an output expansion has a smaller effect on the share of output that suffers from the spot price decrease if the firm has committed a larger part of its output to the retail market. Tangerås and Wolak (2017) show that the equilibrium degree of vertical integration depends crucially on the market design. The benefit of increased vertical integration is to compel competitors to reduce their output in the short-term market. The reason this works is because vertical integration acts as a credible commitment to behave aggressively in the short-term market. However, increasing the volume sold in the retail market also reduces the retail price and drives down retail profit. Some of this retail price effect spills over to other local markets when the retail price is uniform over a larger territory, which causes vertically integrated firms to sell a larger share of their output in the retail market when there is one large retail market compared to the case when there are many local retail markets. This increased vertical integration in turn improves short-term market performance.

The results in Tangerås and Wolak (2017) indicate that in Europe it is mainly beneficial to reduce the size of zones for producers. From a contracting point of view, it could be beneficial to have large zones for consumers.

Table 2: Some issues and potential remedies for centralized day-ahead markets.

Issue	Remedy
Budget imbalanced due to uplift payments	1) Design tariffs to minimize welfare losses, subject to an acceptable welfare distribution. 2) Make budgets balanced by setting market prices sufficiently high so that no plant that is called to produce would make a loss.
Uplift payments give discriminatory pricing, which cause inefficiencies.	1) Restricts offers to have a shape/slope that is similar to the shape/slope of the marginal cost. 2) Avoid discriminatory pricing by setting market prices sufficiently high so that no plant that is called to produce would make a loss.

Non-transparent market and inefficient hedging due to uplift payments.	Avoid uplift payments by setting market prices sufficiently high.
Illiquid financial markets due to nodal pricing.	Use discrete auctions instead of continuous trading in financial markets.

Table3: Some issues and potential remedies for decentralized day-ahead markets.

Issue	**Remedy**
Collusive bidding	Restrict number of intra-day auctions.
Inefficient allocation of transmission capacity and congestion rents in intra-day market.	Restrict number of intra-day auctions.
Inefficiencies due to zonal pricing	1) Increase number of zones for producers. 2) Introduce flow-based zonal pricing

5 Quantitative comparisons

5.1 Heuristic-based simulations

Ideally one would evaluate market designs by means of Nash equilibria. But existing equilibrium-oriented comparisons of centralized and decentralized markets are limited to simplified duopoly markets, as in Sioshansi and Nicholson (2011). Elmaghraby et al. (2004) and O'Neill et al. (2005) outline computational approaches that could potentially be used to solve for equilibria in electricity markets with non-convexities. Unfortunately, it is computationally challenging to use a game-theoretic approach to evaluate large markets with many plants and producers. Some authors have managed to simulate large markets by heuristic-based approaches. Sioshansi et al. (2008) assume that producers would bid truthfully in centralized markets, which contradicts our discussion about distorted cost information in bids of centralized markets with uplifts, and the findings in Sioshansi and Nicholson (2011). As a result Sioshansi et al. (2008) find that the centralized market is efficient and without mark-ups associated with pay-as-bid pricing. To reflect coordination problems in a decentralized market, they consider a heuristic winner-determination rule with an inefficient dispatch. Sioshansi et al. (2008) simulate the New England market. They find that electricity prices are higher for a decentralized design compared to the centralized design. Moreover, the centralized system has 4.25% less welfare losses. Camelo et al. (2018) make related simulations for the Colombian market, where they find that a centralized market would reduce welfare losses by 3.32%, compared to a decentralized market. It is difficult to say to what extent these inefficiencies are driven by the model assumptions rather than by actual differences between centralized and decentralized markets. In particular, the heuristic simulations neglect that repeated trading and intra-day trading would mitigate coordination issues for decentralized markets.

5.2 Empirical evaluation of centralized and decentralized markets

On December 1, 2010, ERCOT, the electricity market in Texas switched from a decentralized to a centralized market design. Zhang (2016) has evaluated this policy reform and finds that the new centralized design reduced production costs by around 0.5%. Zarnikau et al. (2014) find that spot prices were reduced by 2% on average. During the ERCOT redesign, the day-ahead market also changed from zonal to nodal pricing and the length of delivery periods was shortened from 15 to 5 minutes (Zarnikau et al., 2014). It is thus unclear whether the improvement in efficiency comes from the centralization of the day-ahead market or higher time/geographical resolution of the day-ahead market.

In 2009, Colombia changed from self-commitment to central commitment in the day-ahead market. In an econometric study, Riascos et al. (2016) find that the change improved production efficiency, even if the transition resulted in more strategic bidding and higher electricity prices. Hence, the efficiency gains were captured by producers.

Mansur and White (2012) empirically estimate the net-benefit of that nineteen Midwest-based firms, which used to trade bilaterally, became members of PJM. It was expensive to implement this change, around $40 million. But this was a non-recurring cost. The estimated yearly efficiency gains were much larger, $163 million/year. Mansur and White (2012) believe that efficiency gains mainly arose from improved information about network congestion.

6 Discussion and conclusions

The US has centralized wholesale electricity markets, while most of Europe has decentralized wholesale electricity markets. In centralized markets, producers submit detailed cost data to the day-ahead market, and the market operator decides how much to produce in each plant. This differs from decentralized markets that instead rely on self-commitment and where producers send less detailed cost information to the operator of the day-ahead market. Ideally, centralized electricity markets would be more effective, as the clearing process considers more detailed information, such as start-up costs and no-load costs. However, the cost information that the market operator receives is imperfect. The bidding format is rather simplified and does not allow producers to express all details in their costs. This is a particular problem for plants with complex cost structures, such as CCGT and cascaded hydroelectric systems. Moreover, due to uplift payments, producers have incentives to exaggerate their costs. Alternative pricing schemes have been discussed in the literature, and some of them avoid uplift payments.

In general, centralized markets are less flexible. The bidding format and clearing mechanism need to be up-dated when new technologies arrive on the supply or demand side. Also, it has been difficult to organize intra-day markets in centralized markets, which made it hard for producers to continuously up-date their dispatch as the forecast for renewable output changes. Recently PJM has introduced intra-day markets, which is a great improvement.

Centralized markets with uplifts payments are not budget balanced. In this report we argue that there is a trade-off between rents and efficiency when designing tariffs that are used to cover the uplift payments. Another issue with centralized markets is that they are very computer intensive and NP-hard to scale up. This is a potential problem as the global trend is to increase the geographical size of electricity markets and to shorten the length of delivery periods. On the other hand, the computational performance and the performance of clearing algorithms are also improving over time. The iterative and computer-intensive clearing process means that centralized electricity markets are opaque and somewhat of a black box. The system operator clears centralized day-ahead markets. Hence, transmission ownership should be separated from system operations to reduce the incentives of the system operator to clear the day-ahead market in a strategic way.

Intra-day markets are more flexible and it is easier to deal with renewable power in decentralized markets. Iterative intra-day trading in a decentralized market can also be used to sort out coordination problems related to non-convexities in the production. But iterative trading also increase the risk of collusive outcomes. Continuous intra-day trading has problems to deal with inter-zonal congestion in an efficient way. It is our belief that discrete, auction-based, intra-day trading is necessary to manage this issue. Self-dispatch means that more of the data processing and dispatch optimization has been delegated to producers, which should increase their costs. Transaction costs are likely to be higher in a decentralized market. Block orders reduce this problem, but on the other hand they also introduce some of the drawbacks of a centralized market. Financial markets and hedging work better for decentralized markets with zonal pricing. Still, we believe that European decentralized day-ahead markets can be improved by considering network constraints in more detail. Many countries would benefit from reducing the size of their zones, especially on the supply side. For political reasons and to encourage producers to sell more in the forward market, there are advantages with having large zones for consumers. The flow-based approach that is advocated by EU should also improve market efficiency.

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