Rethinking Restructured Electricity Market Design: Lessons Learned and Future Needs

Antonio J. Conejo[a,b], Ramteen Sioshansi[a,*]

[a] *Department of Integrated Systems Engineering, The Ohio State University, 1971 Neil Avenue, Columbus, Ohio 43210, United States of America*

[b] *Department of Electrical and Computer Engineering, The Ohio State University, 2015 Neil Avenue, Columbus, Ohio 43210, United States of America*

Abstract

Many principles underlying the design of restructured electricity markets that are in-use today were developed over three decades ago when power systems were considerably different than today's and tomorrow's systems are. Systems of the past typically relied on large dispatchable thermal generators to supply energy. This can be contrasted with power systems today, which are experiencing rising penetrations of weather-dependent renewable energy sources that have limited dispatchability. Moreover, many power systems are experiencing growing adoption of distributed energy resources and novel uses of electric energy by end customers, which adds to demand uncertainty and variability. However, these technologies also provide opportunities for more active participation of the demand-side in maintaining system reliability and service quality.

Given these marked changes in the architecture of electric power systems, we are at a unique point at which the tenets of restructured electricity market design can be re-evaluated. While this re-examination is largely driven by changes in power system designs, we can also rely on lessons learned from the past three decades of market-restructuring experience. In this paper, we highlight some of the challenges in designing electricity markets brought about by changes in system designs. We also discuss a number of lessons learned from market designs that have been implemented. We then suggest some important principles that should underlie future reforms of electricity market designs and raise design questions that require further research and examination.

Keywords: Electricity market, market design, pricing, scheduling, operations

1. Introduction

Electricity-market restructuring has a history dating back to the 1980s [1]. In many cases, reforms of electricity markets were undertaken to improve the operational and planning efficiencies of power systems. Market restructuring can also serve to transfer technology and cost risks away from customers to investors. Many of the principles underlying the market designs that were employed then (and which survive today) are rooted in the historic architecture of electric power systems. However, the electric power systems of today and tomorrow 'look' considerably different than most power systems did thirty years ago.

Electric power systems of the past typically relied on a small number of large dispatchable thermal generators to supply energy needs. This historical system design is unsustainable, however. In a recent assessment, the United States Energy Information Administration projects that world energy consumption will grow by 52% between the years 2010 and 2040 [2]. Much of this consumption increase is driven by long-term economic growth. Three Intergovernmental Panel on Climate Change scenarios suggest that this

*Corresponding author

Email addresses: `conejonavarro.1@osu.edu` (Antonio J. Conejo), `sioshansi.1@osu.edu` (Ramteen Sioshansi)

increasing energy (and associated fossil-fuel) use may result in atmospheric CO_2 concentrations that are between 22% and 111% greater than the 450 parts per million stabilization scenario [3]. Adding to climate concerns are the risks of unanticipated shocks in the supply of fossil fuels.

These realities, combined with renewable generation technologies becoming cost-competitive with conventional alternatives [4, 5], have contributed to a radical transformation of many electric power systems. Power systems have seen increasing penetrations of renewable energy sources, with these trends expected to continue into the future. The use of renewable energy is not a panacean solution, however, and renewables can have negative impacts on system operations and planning. Increasing penetrations of renewables, such as wind and solar, mean that a decreasing portion of the energy supply is dispatchable [6–9]. This is because real-time wind and solar availabilities are weather-dependent, uncertain, and variable. Another burgeoning problem associated with the use of renewable resources is that they can increase the ramp in the net load profile (*i.e.*, demand less renewable output). This effect of renewable generation results in what has been colloquially termed the 'duck curve,' which can increase the need for flexible dispatchable resources that can ramp their output up and down quickly [10]. The duck-curve effect can also result in 'overgeneration' situations, in which the system must curtail the output of renewable generators to maintain load balance.

Many power systems are also undergoing important demand-side changes. One is the growing adoption of distributed energy resources by end customers [11, 12]. These resources are largely 'uncontrollable' by system operators. Distributed renewable resources carry the same issues of being weather-dependent, uncertain, and variable that utility-owned and -operated renewable resources do. However, distributed renewable generators raise an additional 'visibility' issue insomuch as many electric utilities do not have separate meters to monitor and be able to forecast their real-time output. Even dispatchable distributed energy resources can be challenging for system operators to manage, because they may be controlled by the end customer or another entity (*e.g.*, an aggregator) that does not coordinate their operating behavior with that of the overall system. As such, forecasting available energy from distributed energy resources can be challenging and may require costly and widely distributed monitoring and sensing equipment. Thus, distributed energy resources are often modeled as increased demand uncertainty. Other factors, such as novel uses of electricity (*e.g.*, for electromobility [13]), can also increase demand uncertainty. On the other hand, distributed energy resources and novel uses of electricity may engender greater demand-side flexibility, which can mitigate some of the challenges associated with renewable integration [14].

Despite these fundamental changes in the supply and demand sides of electric power systems, the market models and structures that are used to coordinate the two sides of the system largely have not kept pace. Instead, today's market designs are legacies of historical system designs that assume a system that mostly relies on dispatchable thermal generation and little supply- or demand-side uncertainty.

As one example of this disconnect between today's market and system designs, many restructured electricity markets rely on day-ahead and real-time markets to coordinate electricity supply. The historical role of the day-ahead market is, in part, to provide commitment, dispatch, and price information to thermal generators that may have lengthy startup and slow response times (*e.g.*, steam turbines can take more than six hours to startup whereas nuclear plants can require multiple days' planning notice to cycle on or off). Thus, the day-ahead market ensures that such generators are online and available to provide energy when needed by the system. The real-time market is largely intended to provide imbalance energy and capacity to manage relatively small errors in forecasting load day-ahead.

A day-ahead market may be of limited value, however, to a power system that relies on renewable energy for a non-trivial portion of its energy. This is because weather-dependent renewable energy sources may not be able to accurately predict their real-time availability day-ahead. Moreover, inflexible generators with slow response times may see a diminished role in such power systems of the future. Instead, there may be a growing role for flexible dispatchable generators (*e.g.*, natural gas-fired combined-cycle and combustion-turbine generators), which can provide balancing energy and ramping capabilities to the system. With such a system design, a market structure that relies on day-ahead and real-time markets *only* may be an inefficient paradigm.

Some market redesigns have taken place over the past few years in reaction to changes in system designs. Examples include revisions to capacity markets to accommodate the weather dependence of renewable energy resources [15] and the introduction of a flexible ramping product in the California ISO market to mitigate the duck curve effect [16, 17]. However, these revisions to market rules have been largely piecemeal attempts to address the unique market-design, operational, and pricing challenges that are raised by renewable energy resources. It is not clear that applying 'patches' of these types to an underlying market design that is not tailored to the design of today's and tomorrow's power systems will provide the most efficient coordination mechanism in the long term.

The academic literature related to market redesign is also largely piecemeal in nature. Nanduri and Das [18] provide a comprehensive review of market-design issues and areas of research. Given that this survey is conducted in 2009, it mainly discusses issues related to price forecasting, bilateral contracting, auction design and the resulting offering strategies undertaken by market participants, and market power (*i.e.*, issues of importance at the time). Thus, this survey does not consider the impacts of future system architectures on market design. Biskas *et al.* [19, 20] propose a market-splitting algorithm that could be implemented in the emerging integrated day-ahead European market. Sleisz and Raisz [21] propose a computationally efficient market-clearing model that can account for supply orders and ramping limitations. Müsgens *et al.* [22] analyze the incentive and efficiency properties of balancing markets, with a focus on the design that is implemented in Germany. Casolino *et al.* [23] examine the problem of market design from the perspective of a natural gas-fired combined-cycle generator. Specifically, they analyze how different design choices can affect the optimal participation and profitability of such generating units.

This paper contributes to this literature by providing a more comprehensive framing of the important issues that should be considered as market designs continue to evolve to address the various changes in the underlying system. We do this in three parts. First, in Section 2 we provide a high-level survey of restructured-electricity-market designs that are in-use today. This includes a discussion of the evolution of designs over the past thirty years and some of the major lessons learned. This does not include a detailed accounting of any particular market design, as that would entail an exhaustive and lengthy survey. Next, Section 3 provides a more detailed accounting of the major challenges that market designers and operators must contend with, given the ongoing changes to the designs of electric power systems. We see a number of important challenges. First, markets must evolve to better represent uncertainties in the supply and demand sides of the system. Second, the physical constraints of the system and production facilities should be properly represented in market models. Third, pricing and market rules should balance system efficiency with respect for private property rights. Finally, the retail side of the market should be redesigned to allow for demand-side resources to participate actively in system operations. Section 3 also surveys some of the work that is presented in the technical literature that provides partial solutions to some of these challenges. Section 4 describes a number of important design principles that should be considered in redesigning future restructured electricity markets. This section also highlights some important research questions that require further study to most efficiently refine restructured-electricity-market designs. Section 5 concludes. The appendix provides a summary of a number of terms that are used throughout the paper.

2. Current Restructured-Electricity-Market Designs

Each restructured electricity market (even those within the same country) have numerous differences in their designs. Moreover, these market designs are undergoing constant refinement to deal with new challenges that market operators, regulators, market monitors, and other stakeholders encounter. Indeed, one of the challenges of designing restructured electricity markets is that they always entail tradeoffs. Designers recognize that market models cannot fully capture all of the nuances of power system planning and operations. Many of the refinements in market designs have arisen because the market-design choices originally made resulted in important market inefficiencies that subsequent reforms mitigate.

This section gives a high-level overview of the major design elements that are in-use in many restructured electricity markets today. This discussion is focused around four common themes: unit commitment and dispatch, future markets and capacity planning, transmission representation, and the role of the demand side. Although these four themes are important in market design, they alone do not entail a comprehensive market design. However, these four themes are some of the most important considerations in market design and are increasingly important as power system designs are evolving.

2.1. *Unit Commitment and Dispatch*

Unit commitment and dispatch is one of the most important aspects of restructured electricity markets. For one, unit commitment and dispatch determines how the system is operated in real time, meaning that it is vitally important for short-run system efficiency. This includes the dispatch of generation units to provide energy and the reserving of supply- or demand-side capacity for ancillary services. Some markets also allow for active participation of the demand side in maintaining real-time load balance, for instance through active price-responsive bids for energy demand. This aspect of market design is discussed further in Section 2.4.

Unit commitment and dispatch is also important because it provides prices that ensure long-run system efficiency. Stoft [24] uses a stylized screening model to demonstrate this. He shows that if the energy that is produced by generators is remunerated based on the marginal cost of supply, the prices are equilibrium-supporting. In this context, equilibrium-supporting prices means that so long as the generation mix is socially optimal (*e.g.*, a least-cost mix), all generators fully recover their fixed and variable costs through energy revenues. Otherwise, if the generation mix is not socially optimal some generators will not recover their costs (incentivizing their exit from the market) and others will earn positive profits (incentivizing entry of those technologies). Market exit and entry should continue in this fashion until the generation mix and prices reach a zero-profit equilibrium, which corresponds to a socially optimal mix.

A major difference in how the unit commitment and dispatch processes take place in various markets is the extent to which the decisions are centrally coordinated. Most electricity markets that underwent restructuring in the 1980s, 1990s, and early 2000s initially had a relatively decentralized design. Such designs rely on a pool-type market for relatively simple products (*e.g.*, energy and various types of reserves or ancillary services) that are traded and sold. These decentralized designs rely on individual generating firms to manage the constraints on the operation of their generating units and to internalize their non-convex operating costs. Examples of the types of constraints that a generating firm must manage are ramping limits, minimum load levels, and minimum-on and -off times when a unit is started up or shutdown. Non-convex generator-operating costs largely arise from the fixed costs associated with starting a generator and its no-load cost while online. Some generation technologies (*e.g.*, natural gas-fired combined-cycle units) can also have non-convex cost structures associated with different operating modes when they generate at part versus full load.

Many markets, including most European [25, 26] and the Australian [27] markets, retained largely decentralized designs. Conversely, most markets in the United States evolved over time toward having more centralized designs [28]. Such markets endow a market operator (which, in many cases, is the same entity that manages the transmission system) with the authority to make binding operating decisions for generation units. These markets do not trade simple products, such as energy and ancillary services, in a pool-like setting. Rather, generation units submit complex offers, which specify their complete cost and constraint parameters, to the market operator. The market operator then solves a market model, which is often formulated as a mixed-integer optimization problem, to determine the commitment and dispatch of all of the generating units [29].

The two market designs have advantages and disadvantages relative to one another. A decentralized market design better respects the property rights of asset owners. This is because centralized designs endow the market operator with the right to make binding operating decisions for generators. In a decentralized market, generating firms make these decisions individually. On the other hand, decentralized unit commitment and dispatch raise some important coordination problems. One is that the decentralized design relies on individual generators to determine when to have their generating units online. In a centralized design these decisions are made in a fully coordinated manner. Assuming that the market operator in a centralized design has the true cost and constraint parameters for all of the generating units, the centralized design will *de facto* more efficiently coordinate these decisions [30]. This is a strong assumption, however, because generators have incentives to misstate their cost or constraint parameters to manipulate the commitment and dispatch of the system and the resulting prices and revenues earned [31]. Another type of coordination issue centers around the provision of different services. Many decentralized market designs clear the markets for energy, reserves, and ancillary services separately. This creates an obvious inefficiency, because in many cases these services are potentially provided by the same agents (*e.g.*, generating units or flexible demands).

Separating the markets for these services requires agents to choose which services to offer. Most centralized market designs co-optimize the provision of energy, reserves, and ancillary services, which mitigates this source of inefficiency.

Another issue that is raised by the two market designs relates to pricing. Pricing in centralized market designs is complicated by the fact that the market model explicitly represents non-convex generation costs and binary unit commitment decisions. As such, marginal prices can be economically confiscatory in the sense that the market solution requires some generating units to be online and producing energy at a net profit loss [32]. Economic confiscation is not sustainable in the long-run as it either incentivizes generators to exit the market, which can threaten system reliability, or to misstate their costs to manipulate the resulting marginal prices, which destroys short-term market efficiency. The economic confiscation problem can, alternatively, be addressed through supplementary uplift payments [33]. These payments are discriminatory and complex to calculate and economically interpret, however. Moreover, these pricing schemes can have undesirable properties, such as eliminating the economic rents of inframarginal units [34]. As such, most centralized markets address the economic confiscation problem by providing generators with supplemental make-whole payments. These payments provide for any shortfall between the revenues that a generator earns from marginal prices and its operating cost (as computed by the market operator on the basis of the supply offers that the generator makes to the market). The cost of these make-whole payments are typically uplifted to load.

Decentralized market designs overcome these pricing issues by forcing generating firms to internalize their non-convex costs when submitting offers to supply energy, reserves, and ancillary services. As such, the marginal prices that are derived from the market model, which represent very few (if any) non-convexities, should not lead to such economic confiscation (so long as generators properly internalize their costs). This approach to handling non-convex costs does imply, however, that at least some generators offer energy and other products above their true marginal cost. This gives rise to inefficiencies, however, because the market is not cleared on the basis of true costs. Some decentralized market models also represent limited non-convexities. Examples can include minimum-load levels or 'blocked' dispatch that requires a generator to be dispatched over some minimum number of hours. These types of constraints can result in prices that are not individually rational, in the sense that a generation offer that is 'in the money' is not accepted due to a non-convex constraint. However, because generating firms internalize their non-convex costs, decentralized market designs rarely (if ever) require uplift payments due to economic confiscation [32].

We can illustrate these pricing issues using a simple example. Consider a single hour in which there is a 100-MW demand with a demand utility for using electricity of \$40/MWh. There are two generators, both of which are currently shutdown, that can be used to supply this demand. Table 1 summarizes the technical characteristics of these generators. The maximum capacity only applies if a generator is switched on. If a unit remains off, then its production must equal zero.

Table 1: Generation-Unit Data for Market-Clearing Example

Unit	Minimum Capacity [MW]	Maximum Capacity [MW]	Marginal Cost [\$/MWh]	Startup Cost [\$]
1	0	80	10	0
2	0	40	20	100

We first consider a centralized design, which relies on a unit commitment-based model to clear the market. Both units must be committed to serve the load and Table 2 summarizes the resulting optimal dispatch and profits of the units. Because Unit 2 is marginal, the market-clearing price is set equal to \$20/MWh. The third column of Table 2 lists the profits that are earned by the two units from receiving these energy payments *only*. While Unit 1 fully recovers its costs and earns a net profit, Unit 2 is forced to operate at a net loss if it only receives energy payments. Indeed, Unit 2's profits remain negative regardless of how much energy it produces.

The last column of Table 2 shows that Unit 2 must be given a \$100 make-whole payment to allow it to

Table 2: Generation-Unit Dispatch and Profits for Market-Clearing Example with Centralized Market Design

Unit	Dispatch [MW]	Profit From Energy Payments Only [$]	Make-Whole Payment Required [$]
1	80	800	0
2	20	−100	100

recover this profit loss. The total load payment is $2100, which exactly corresponds to the sum of the total revenues earned by the two units, which are $1600 and $500, respectively. Total producer welfare is $900 and consumer welfare $1900, meaning that social welfare is $2800.

We next consider a decentralized market design, whereby generators internalize their non-convex startup costs and are allowed to submit offers that are above marginal cost. Suppose that Unit 1 continues to offer its supply at its true marginal cost of $10/MWh, while Unit 2 offers its supply at a cost of $25/MWh. Table 3 summarizes the resulting dispatch and profits of the units. Because Unit 2 remains marginal, the market-clearing price is now set equal to $25/MWh.

Table 3: Generation-Unit Supply-Offers, Dispatch, and Profits for Market-Clearing Example with Decentralized Market Design

Unit	Supply Offer [$/MW]	Dispatch [MW]	Profit From Energy Payments Only [$]
1	10	80	1200
2	25	20	0

The final column of Table 3 shows that with this market outcome Unit 1 earns a profit of $1200 while Unit 2 exactly breaks even, eliminating the economic-confiscation problem that arises in the centralized market design. Thus, no make-whole payments are needed. This market outcome results in a load payment of $2500, producer welfare of $1200, consumer welfare of $1500, and social welfare of $2700. Comparing the market outcomes under the centralized and decentralized designs illustrates some of the tradeoffs between these market designs. The centralized design requires discriminatory make-whole payments to ensure that all of the units recover all of their costs, whereas a decentralized design does not. However, the decentralized design achieves cost recovery through a higher market-clearing price, which results in some social welfare losses relative to the centralized market design.

Another issue that arises with pricing in decentralized market designs concerns the different products clearing in separate markets, which can give rise to perverse prices. A well known example of this phenomenon concerns the pricing of different reserve and ancillary service products [35]. Ancillary service products can be differentiated on the basis of their service qualities. For instance, frequency regulation can be viewed as a superior product compared to contingency reserves, because frequency regulation requires a much faster response time. As such, one would expect that higher quality services should command a higher price. Indeed, such rank ordering of prices is typically needed to maintain incentive compatibility. Otherwise, absent such a rank ordering, agents that can provide a higher quality service (*e.g.*, frequency regulation) may opt to provide a lower quality service (*e.g.*, contingency reserves) instead. Addressing these types of price reversals in decentralized markets often entails adding complicating rules to the market-clearing process of the different services [35].

In terms of the timing of market clearing, most markets rely on day-ahead and real-time markets. The day-ahead market typically clears at about midday on the day before the operating day in question. This market uses forecasts of system conditions (*e.g.*, load and supply availability) on the operating day to provide market participants with day-ahead schedules and corresponding prices. Historically, this day-ahead market clearing was of great importance to some generation technologies that require advance notice to ensure that they are online and able to deliver energy and capacity when the system requires it (*e.g.*, nuclear and steam-turbine units). Some flexible loads (*e.g.*, an industrial facility that may opt to furlough its operations) may also benefit from a day-ahead schedule.

The real-time market clears much closer to the actual operating period. The primary purpose of the real-time market is to allow for changes in production and consumption schedules, to accommodate differences between day-ahead forecasts of system conditions and actual conditions that are observed in real time. Originally, most real-time markets cleared hour-ahead. This was largely due to computational limits, which made market-clearing closer to actual delivery intractable. As computational capabilities advanced over time, many markets evolved toward fifteen- or five-minute-ahead real-time markets. The real-time market represents the last trading opportunity between producers and consumers prior to actual energy delivery.

Some restructured markets have introduced additional market-clearing opportunities between the day-ahead and real-time markets. Many markets in the United States now include an additional reliability unit commitment model. The reliability unit commitment model is typically solved in the afternoon or evening following the clearing of the day-ahead market. The purpose of the reliability unit commitment is to provide the system operator with an additional opportunity to commit units. This may be prudent if, for instance, its afternoon or evening forecast of system conditions on the subsequent operating day are vastly different than the forecasts that are used in the day-ahead market model. The reliability unit commitment is largely intended to provide for system reliability. As such, the reliability unit commitment model does not generate prices to be used for market settlement. Instead, settlements are made using day-ahead and real-time prices.

Other markets (*e.g.*, a number of European markets) include some number of intra-day markets that clear between the day-ahead and real-time markets. The purpose of these markets is to allow producers and consumers to make adjustments to their day-ahead schedules. Market participants may wish to make such adjustments if, for instance, they have updated forecasts of system conditions on the subsequent operating day. Thus, these intra-day markets mimic the role of the reliability unit commitment. However, markets that employ these intra-day markets rely on market participants to individually adjust their production and consumption schedules, as opposed to making such adjustments in a centralized fashion.

2.2. Futures Markets and Capacity Planning

Futures markets play a number of roles in restructured electricity market design. We focus our discussion here on two in particular: (i) hedging against price volatility and (ii) capacity planning and investment.

Most markets have developed either dedicated or ancillary markets for trading of energy-related products on a forward basis. Forward contracting can have terms spanning from one week to multiple years. In many European countries, as an example, there are dedicated futures markets, which are independent of general commodity futures markets, for over-the-counter trading of electricity. These electricity futures markets are specifically tailored to electricity trading, with a variety of financial products to hedge against day-ahead- and real-time-price volatility. The United States, as another example, has organized over-the-counter trading of electricity futures, which is integrated with general commodity futures markets. The United States also sees large volumes of forward electricity trading through bilateral contracting.

Another important role that futures markets play is in long-term capacity planning and investment. Most restructured electricity markets initially adopted what is known as an energy-only design. Such a design relies on the property that marginal spot pricing is equilibrium supporting, so long as prices are allowed to rise to the value of lost load when involuntary load curtailment must take place [24]. Thus, in an energy-only design there is no explicit market mechanism for capacity to be built. Instead, existing capacity is maintained, new capacity is installed, and uneconomic capacity is retired on the basis of anticipated spot-market prices (which are derived from the day-ahead and real-time markets). Over-the-counter or bilateral contracting tend to play important roles in this process, however. This is because investors may be wary of building or maintaining capacity solely on the basis of volatile spot-market prices. Futures contracts can provide needed price stability for such investments. Energy consumers typically also have incentives to engage in such long-term contracting. This is because many consumers prefer price stability to the potential volatility of day-ahead and real-time prices.

Issues surrounding the exercise of market power can arise with energy-only market designs, however. This is because it can be difficult to determine if price spikes are due to market fundamentals (*e.g.*, high marginal cost or scarcity of supply at a given time) or generating firms behaving uncompetitively in offering their generation to the market. Regulators are often left to use blunt instruments, such as offer or price caps or market monitoring coupled with offer mitigation, to limit the exercise of market power. The issue with using such interventions in an energy-only market design is that they tend to limit scarcity pricing, creating what is referred to as a missing-money problem.

One way to address this missing-money problem, which has been adopted in a number of restructured electricity markets, is to supplement payments from the day-ahead and real-time markets with a longer-term capacity market. Stoft [24] shows, using the same screening model, that the market can be equilibrium supporting if: (i) energy prices are capped by the operating cost of the generating technology with the highest marginal cost (as opposed to prices being able to rise to the value of lost load) and (ii) all generators are given a supplemental capacity payment with the capacity price set equal to the capacity cost of the generating technology with the highest marginal operating cost. This result provides a theoretical basis on which to design a capacity market that delivers long-term efficiency.

Many restructured markets, including those in Australia, much of Europe, and the state of Texas, began and continue to use energy-only designs. On the other hand, a number of restructured markets in the United States, including PJM Interconnection, ISO New England, and New York ISO, have evolved toward using forward capacity markets. There have also been recent discussions of introducing explicit long-term capacity mechanisms in some European markets. In some instances, these mechanisms are technology-specific in that the payments would target specific technologies. The rationale behind these targeted payments is that some technologies are seen as being at risk of exiting the market but being needed to maintain system reliability.

This rationale behind targeted capacity payments is indicative of a growing issue surrounding long-term capacity planning and investment. Policymakers are increasingly using incentive mechanisms or explicit mandates to encourage the deployment of specific technologies (subsidies or quota systems for renewable energy sources [11] are two examples). The deployment of technologies to meet policy goals, as opposed to being driven by fundamental economic principles, can put the system into 'disequilibrium,' in the sense that an energy-only market or a design with energy and capacity payments may not sustain all necessary investments. As a further example of these growing concerns, the Federal Energy Regulatory Commission held a technical conference in May 2017 to solicit stakeholder and expert opinions on how to reconcile the design of efficient restructured wholesale markets with the goals of policymakers (*cf.* Docket Number AD17-11-000).

We do not delve into this issue, except to comment that the types of policy mechanisms that are largely used in the United States and elsewhere (*e.g.*, subsidies and capacity targets) tend to create market inefficiencies. As such, we advocate for more economically efficient policy interventions. For instance, if the rationale behind supporting the deployment of renewable energy is to mitigate concerns around climate change, an explicit tax that internalizes the externality stemming from the use of hydrocarbons would be a more efficient policy intervention.

2.3. Transmission Representation

Markets vary in their representation of the transmission system. Most markets that were restructured in the 1980s and 1990s initially had no (or very limited) representation of the transmission system in their market models. This design choice was made for two reasons. First, computational capabilities were quite limited in the 1980s and 1990s compared to our ability to solve large-scale optimization problems today. As such, high-fidelity representation of the transmission system was simply not computationally tractable. The second reason was that market designers believed that representing the transmission network in market models would cause undue transaction costs for market participants. Transactions costs arise because efficiently pricing energy requires generating a locational marginal price for each network node that is represented in the market model [36]. There was concern that having hundreds or even thousands of potentially different locational marginal prices corresponding to a high-fidelity network model would serve as a barrier to trade.

In light of these concerns, most markets initially had no representation of the network model or used a simplified zonal model. The assumption underlying a zonal design is that only a subset of transmission constraints are prone to consistent congestion. As such, the zonal model assumes that a reasonable approximation of the network can be obtained by representing that subset of constraints and ignoring the others. Moreover, zonal market designs typically allow for new zones to be designated if new transmission constraints are identified as being prone to important or consistent congestion.

As an early example of this, the California market initially had two zones—NP15 and SP15, corresponding to the two ends of Path 15, which is a major transmission corridor connecting northern and southern California—when the restructured market began operation in 1998. However, the zonal model was revealed to have numerous flaws. For one, the assumption of predictable transmission congestion turned out to be an illusion. As such, the transmission system operator would systematically have to undertake corrective (and, at times, costly) changes to schedules of energy injections and withdrawals in real time to ensure feasible transmission flows. Moreover, defining new transmission zones in California was complicated by the fact that such changes typically require stakeholder approval. Because defining a new transmission zone invariably causes price differences between the newly defined zones, zonal decoupling creates economic winners and losers. This fact complicates the process of achieving stakeholder approval. Finally, zonal markets can create perverse incentives for certain market participants (depending on their location within a zone) to artificially create intrazonal transmission congestion. This is because such market participants may have locational market power for relieving the transmission congestion that they create, allowing for rent-seeking behavior.

At the same time that the flaws in zonal market designs were revealed, computational capabilities advanced. Moreover, the markets that initially adopted higher-fidelity representation of the transmission network did not experience dramatic transaction-costs issues. As a result of these three developments, all of the restructured markets in the United States have evolved toward high-fidelity representation of the transmission system. This can be contrasted with restructured markets in most of the rest of the world. For instance, most wholesale national markets in Europe have a single price for the entire national system (meaning that there is no network representation within the country in the relevant market model). There is some historical context in this market-design choice. Many European power systems had overcapacitated transmission systems when their markets were restructured. As such, representing transmission constraints that were rarely binding when these markets were first restructured was not a market-design priority. NordPool is one of the few European markets that has some limited transmission representation, in the form of a zonal model. This means that European system operators are required to undertake heuristic corrective adjustments to injections and withdrawals of energy to ensure feasible power flows. Moreover, these markets are prone to the types of inefficiencies that California and other markets in the United States faced when they employed zonal market models.

We conclude this discussion of transmission representaton with a simple example that illustrates its impacts on dispatch and energy pricing. Consider the two-node, single-line transmission system that is illustrated in Figure 1. Suppose that the market has a single operating period and that there is a single 80-MW demand with a utility for using electricity of $40/MWh at Node 2. Two generating units, one at each node, are available to serve this demand. Table 4 summarizes the technical characteristics of these two units, and we neglect generator startup costs or unit commitment-related considerations in this example. The transmission line connecting the nodes has a 50-MW capacity.

Figure 1: Two-Node, Single-Line Transmission Network for Transmission-Representation Example

We first consider a market that represents the transmission network. The optimal production levels of Units 1 and 2 are 50 MW and 30 MW, respectively. Because the transmission network is represented, there are different locational marginal prices of $10/MWh and $20/MWh at Nodes 1 and 2 respectively. This is because the transmission line is constrained, meaning that each unit is marginal at its local node. Given these prices, the two units earn zero profits. The load payment is $1600, which equals the sum of the $500

Table 4: Generation-Unit Data for Transmission-Representation Example

Unit	Minimum Capacity [MW]	Maximum Capacity [MW]	Marginal Cost [$/MWh]
1	0	60	10
2	0	100	20

merchandising surplus and the revenues of Units 1 and 2, which are $500 and $600, respectively. Producer welfare is $0 and consumer welfare is $1600, meaning that social welfare is $2100.

We next consider a market that neglects the transmission network. This market model gives production levels for Units 1 and 2 of 60 MW and 20 MW, respectively. Because the transmission network is neglected, Unit 2 is the unique marginal generator for the entire network, meaning that there is a uniform market-clearing price of $20/MWh at both nodes. Because this dispatch is infeasible, the system must be redispatched in real time by reducing the output of Unit 1 by 10 MW with a corresponding increase in the output of Unit 2. This redispatch is normally priced at the marginal cost of the highest-cost unit that is redispatched, which in this case is the $20/MWh cost of Unit 2. Once the redispatch is taken into account, Units 1 and 2 earns profits of $500 and $0, respectively. The load payment is $1600, which corresponds to the sum of the revenues of Units 1 and 2, which are $1000 and $600, respectively. Producer welfare is $500 and consumer welfare is $1600, giving social welfare of $2100.

Contrasting these two market outcomes illustrates some important differences when the transmission network is and is not considered in the market model. We see that the final dispatch is identical under the two market designs, however an additional redispatch is required when the transmission network is neglected if any transmission lines are capacitated. We also see that the total social welfare is the same between the two market designs. However, the distribution of the welfare gains differ between them. When the transmission network is modeled, the welfare gains go to consumers and the market operator (by means of the merchandising surplus). In practice, this merchandising surplus that the market operator collects either goes to transmission owners to help finance construction and maintenance of the infrastructure, or to other market participants. When the transmission network is neglected, Unit 1 earns positive profits because it is earning a higher payment on the 50 MW that it sells (after the redispatch is taken into account). When transmission is neglected the market operator does not collect any merchandising surplus.

2.4. Role of Demand Side

When market restructuring was first undertaken, much of the focus was on designing mechanisms to coordinate the supply of energy and capacity. This is in part because the demand-side of the market has historically been viewed as being largely static. That is, electricity demands are relatively (if not completely) price-inelastic and inflexible in the short run. Nevertheless, market designers did have a view toward eventually engendering greater demand-side participation. A classical view of this is to provide consumers with high-power incentives for managing their consumption through time-varying retail pricing, such as real-time pricing [37, 38].

The practical experience with demand-side participation in wholesale markets has been mixed. About 9.3 million customers were estimated to have participated in demand response programs in the United States in 2014.[1] These participating customers delivered an average of about 100 kWh of annual energy savings and reduced peak demand across the United States by about 13 GW. However, a 2006 study of its demand response programs [39] finds that the United States had very limited demand response capabilities overall at the time, representing only 3% of peak demand. Moreover, this study finds that demand response and load management capabilities in the United States fell by one-third between 1996 and 2006, due to diminished

[1] https://www.eia.gov/todayinenergy/detail.php?id=24872

utility support and investment. Overall, participation rates in demand response programs are quite low, estimated at less than 5% in 2016.[2]

Market designs have taken a mixed approach to incentivizing demand response. Industrial and large commercial customers are able, in many restructured markets, to directly participate in wholesale energy, ancillary service, and capacity markets (where the latter exist). Smaller (especially residential) customers are typically barred from directly participating in the wholesale market and must instead do so through their utility or another third party. This dichotomous treatment of small and large customers is in part due to practical considerations. Wholesale market models would become intractable if the loads of all small customers are represented as being price-responsive. Requiring small customers to aggregate their price-responsive demands through a third party addresses this issue. However, this often means that demand responsiveness from small customers is inextricably linked to the ability of utilities to devise innovative programs to incentivize demand response. As an example of this limitation, very few residential customers in the United States face time-varying retail prices. As such, residential customers participating in demand response programs represented about 25% peak-demand savings in 2014, despite residential customers constituting about one-third of electricity demand.

2.5. Illustrative Market Structures

We conclude this section by showing a visual representation of the structure and timing of restructured electricity markets that are in-use in the United States and Europe today, which are shown in Figures 2 and 3. It should be noted that these are very high-level representations of the market structures, and that the designs of individual markets may vary from what is shown in the figures. However, the figures give a high-level sense of how the market designs that are employed differ between the United States and Europe.

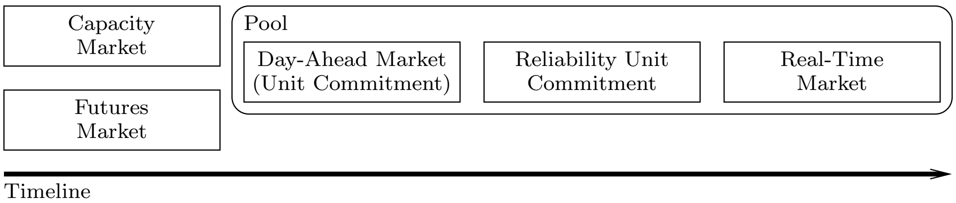

Figure 2: Illustrative Structure and Timing of Restructured Electricity Markets In-Use in the United States

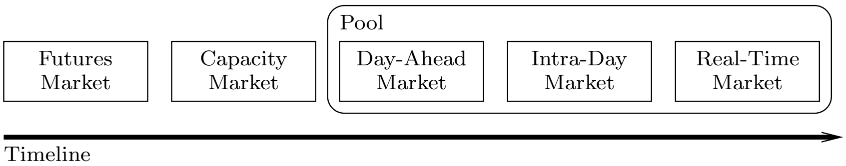

Figure 3: Illustrative Structure and Timing of Restructured Electricity Markets In-Use in Europe

3. Market-Design Challenges and Previous Work

Power systems of the future are expected to have two main characteristics that complicate their operation and market design. First, a growing portion of the energy supply has variable and uncertain real-time availability. Weather-dependent renewable energy resources are a prime example of this. As noted before, the challenges of managing the supply of such resources applies to both utility-scale and distributed energy

[2]This is based on an analysis of preliminary data that are reported to and published by the United States Energy Information Administration through Form EIA-861.

resources. Distributed energy resources can raise an added challenge of having less visibility to system operators, however. This is because the output of distributed renewable generators may only be seen as greater (net-)demand variability by system operators, unless such resources are individually metered.

This leads to the second complicating characteristic, which is greater demand-side variability and uncertainty. In addition to distributed generation, distributed energy storage and greater electrification (*e.g.*, use of electromobility) also contribute to demand-side variability and uncertainty. However, proliferation of distributed energy resources may also provide greater opportunities for demand-side flexibility, so long as the demand side is able to be actively involved in demand management.

Today's market designs are not well suited to operating power systems with these characteristics. This is because these designs were developed around systems that historically consisted of dispatchable generators and predictable and largely inflexible loads. Moreover, the technical literature provides very little in the way of market designs, models, or pricing schemes that can accommodate these characteristics well. Although some market reforms have taken place in recent years, these are to a large extent *ad hoc* adjustments that do not holistically re-evaluate market design.

In terms of integrating variable and uncertain renewable generation into the commitment and dispatch of electric power systems, the existing literature takes two approaches. The first examines the question of how to dynamically set reserve levels in operational models, taking into account the statistical features of the availability of renewable generation [40–46]. While these methods do not have to be used in conjunction with a deterministic market model, they may be well suited for such a framework. This is because these techniques take the stochastic features of renewables into account in setting reserve levels. Thus, the reserve levels 'mitigate' the need for explicitly accounting for this randomness in the model itself. The other body of work expands the unit commitment or dispatch model using either a stochastic- [47], chance-constrained- [48], or robust-optimization [49] framework. These approaches explicitly represent the randomness of renewable availability in modeling operational decisions. Thus, they do not necessarily require reserve levels that account for random renewable availability. Dynamic reserve levels could, however, be included in such models, essentially combining the two approaches.

These works largely neglect the question of how to design a market with increasing randomness and the other features of future power systems. This is because they primarily focus on power system operations without consideration of the incentives of generators to make their units available or long-term investment incentives. Moreover, these works do not consider the question of how to price energy, ancillary services, capacity, and other energy-related services. Generating prices from a market model that is based on a non-convex unit commitment formulation is complicated by economic-confiscation issues [33]. Explicitly modeling uncertainty in market models (whether using a chance-constrained, robust, or stochastic approach) can further complicate commodity pricing.

There are a few works that attempt to study the properties of prices that are generated by a stochastic dispatch model. The seminal work on this topic [50] focuses on the question of whether prices generated using dual variables on the stochastic constraints in a dispatch model are revenue-adequate. That is to say, whether there are any guarantees that the market operator will recover its costs of paying generators from revenues that are raised from reselling energy to end customers. This work proves an *expected*-revenue-adequacy property. Subsequent works [51] focus on the incentive properties of prices that are generated by a stochastic model. These works find that the prices are not necessarily incentive-compatible, because in certain scenarios a load may be cleared to consume energy at a price above its demand utility and generators may be dispatched to produce energy at prices below their marginal costs. In essence, these works find that while stochastic prices are 'well behaved' in expectation, inefficiencies and incentive-compatibility issues can arise in particular scenarios. A related, but thus far unanswered, question is what impacts these stochastic prices would have on long-run investment incentives.

None of these works consider the broader question of how electricity markets should be designed in light of the paradigm shifts electric power systems are undergoing. It should be stressed that electricity market design, as we view it, is more than simply an operational model and a pricing rule. Rather, market design constitutes how suppliers and loads interact with the market; the timing, scope, and scale of the interaction(s); what authority the market operator has to make binding decisions; the models used by the market operator; and the pricing rules.

4. Principles for Efficient Electricity Market Design

Building on the discussion in the preceding sections, we outline here six principles, on which we believe (re)designs of future electricity markets should be based. These principles are informed by lessons learned from current or past market designs, as well as market-design proposals that appear in the technical literature. We also, as appropriate, raise market-design questions that are not well understood. These questions can be the basis on which future research is conducted.

4.1. Principle 1: Multiple Successive Trading Auctions

Market auctions in electricity markets of the future will increasingly takes place without perfect information. This can be due to the expected proliferation of a number of technologies, including weather-dependent renewable-energy sources and distributed energy resources. To deal with this uncertainty, we believe that it is prudent for the market to consist of a number of successive auctions until reaching energy delivery. This can be contrasted with the design of many markets today, which consist of day-ahead and real-time markets. These market constructs that are in-use today may be overly rigid to accommodate the uncertainty and variability that systems of the future will entail. From the viewpoint of market participants (both on the supply and demand sides of the system), this sequence of auctions allows for both correcting errors and taking advantage of the fact that uncertainty vanishes as energy delivery approaches.

Although a sequence of auctions is not common in all restructured markets, some, such as the OMIE, which operates in Spain and Portugal, do employ a sequence of auctions. Moreover, the sequence of auctions that we propose mimics the role of the reliability unit commitment that is employed in a number of markets in the United States. We see two major differences between our proposal and the reliability unit commitment. First, the sequence of auctions that we propose allow market participants themselves to adjust their production or consumption schedules as new information becomes available. The reliability unit commitment is, conversely, a highly centralized process whereby the market operator uses its own information and forecasts to commit additional units (as it sees fit). Our proposal allows for aggregation of information from individual market participants. Secondly, our proposed sequence of market auctions would be financially binding, with prices generated for market settlement. Reliability unit commitment models are not normally used for market clearing.

An important research question that this principle raises is how the market auctions should be timed. Part of this question is how far in advance the market auctions should begin clearing. For instance, a day-ahead market may be of no value in a system that consists entirely of weather-dependent renewable generators and highly flexible natural gas-fired units. On the other hand, if some inflexible technologies, such as nuclear plants, remain in the system, then day- or week-ahead market auctions may be beneficial. A second question is how often the market auctions should re-clear. For instance, there may be little information gained regarding renewable availability between day- and eight-hour-ahead periods. However, there may be significant information gains between eight-hours ahead and real time. This could suggest that there is no need for successive market auctions between day and eight-hours ahead, but then auctions with some frequency between eight-hours ahead and real time.

4.2. Principle 2: Precise Representation of the Physical Layer

Market models should all incorporate a relatively detailed representation of the transmission network. This is because the transmission network constitutes an important physical reality that cannot be ignored or misrepresented. Practical experience demonstrates that ignoring the transmission network or misrepresenting it (*i.e.*, through a zonal model) creates inefficiencies, gives poor pricing properties, causes cross subsidies, and raises incentive issues [52]. Restructured markets in the United States demonstrate that locational marginal pricing does not create undue transactions costs. Finally, computational capabilities are at a point at which there is no rationale related to model tractability for not representing the transmission network in market models.

There is, however, some flexibility in how exactly the transmission network is represented. For instance, a dc linearization of the network may be employed in markets that are temporally 'far' from energy delivery (*e.g.*, week- or day-ahead and intra-day markets). Conversely, market models that are 'closer' to energy delivery (*e.g.*, the real-time market) may employ a more accurate ac representation of the network. This raises a question of the extent to which such a dichotomous representation of the transmission network may introduce inefficiencies or incentive issues.

4.3. Principle 3: Decreasing Uncertainty Representation as Energy Delivery Approaches

Markets that are temporally distant from energy delivery can be subject to a great deal of uncertainty. Thus, the corresponding market model should represent such uncertainty, for instance via chance-constrained-, robust-, or stochastic-optimization techniques. Markets that are closer to energy delivery do not involve significant uncertainty. Thus, the corresponding market model may only need to represent limited uncertainty or may be reasonably approximated as being deterministic. Market models that explicitly represent uncertainty are not currently in-use in any electricity systems. However, some markets, such as ISO New England and NordPool, are considering introducing them.

There are a number of outstanding questions related to implementing market models that explicitly represent uncertainty. One pertains to how uncertainty is represented (*e.g.*, via chance-constrained, stochastic, or robust optimization). These different methodologies introduce tradeoffs in terms of what the market operator is assumed to know and the extent to which it is 'conservative' in making operational decisions. Another question is how explicitly uncertainty should be represented in different market models. For instance, market models that are very close to energy delivery may be reasonably approximated as being deterministic. However, it may still be prudent to set dynamic reserve levels for added operational robustness. A third issue surrounds pricing of commodities in the market. Although some formative works examine the properties of prices that are generated by stochastic market-clearing models, more questions than answers remain today. The market operator must be confident that the prices that are generated by the market model are revenue adequate. Incentive-compatibility of the prices is also important. Finally, the incentives for long-term investment and retirement of generation, transmission, and load is critically important and (to our knowledge) not studied at all as of yet.

4.4. Principle 4: Co-optimization of Energy and Reserves

Energy and reserves are provided by the same types of facilities (*e.g.*, generating units on the supply side and responsive consumers on the demand side). As such, the provision of energy and reserves should be co-optimized (*i.e.*, these two types of commodities should be scheduled and dispatched simultaneously to maximize social welfare). The provision of energy and reserves is typically co-optimized in markets in the United States. However, many other restructured markets separate the clearing of provision of these services, either through sequential or simultaneous auctions. Moreover, supply- and demand-side resources are not necessarily treated symmetrically in clearing energy and reserve resources.

4.5. Principle 5: Private Property Rights

Market designs that are in-use today vary in their treatment of private property rights. Most markets in the United States confiscate private property rights, insomuch as the market operator has the authority to make binding decisions regarding the commitment of generating units. Conversely, most other markets (outside of the United States) reserve these decisions for the owners of generation units. Surprisingly, the efficiency properties of these two contrasting market designs are not well understood. To our knowledge, there is a single work in the academic literature [53] that makes a formative effort to contrast the efficiency properties of these two market designs. However, this work is highly stylized and assumes away many of the intricacies of real-world markets.

We see several competing issues in this aspect of market design. One is that granting the market operator the authority to make binding unit commitment is *de facto* more efficient than leaving these decisions to individual generators, so long as the market operator has *true* cost and constraint information on which to make such decisions. Thus, the incentive properties of the two 'competing' market designs is a critically important issue that is not well understood. Secondly, pricing is significantly more complicated in centrally committed market designs, in which the market operator makes binding unit-commitment decisions [33]. This is because the market model in a centrally committed market represents non-convexities. Conversely, a decentralized market design leaves it to individual market participants to internalize these types of non-convexities.

4.6. Principle 6: Demand Participation and the Role of the 'Utility'

There is an obvious benefit in facilitating the involvement of the demand side of the power system in the market. This is because to the extent that the demand side is willing to do so, it may provide a lower-cost source of flexibility than the supply side of the system does [37, 38]. Moreover, demand responsiveness may be a significantly less costly means of accommodating the variability and uncertainty in renewable-energy availability [14, 54–57]. It is, thus, desirable that the demand participates in the market either by itself or through coordinators and aggregators.

An 'unknown' in this regard is how best to incorporate and incentivize demand responsiveness into the market-clearing process. Relying on incumbent utilities to provide such demand responsiveness has potential limitations, insomuch as it relies on utilities to innovate in their provision of energy services to end customers. Moreover, to the extent that utility profits are tied to the volume of energy sales, they may have disincentives to pursue innovative business models that rely on engendering responsive customer demand. For this reason, we believe that it is prudent to re-examine the role of the 'traditional' utility in power systems of the future. For instance, it may be beneficial to transform the utility into a true provider of last resort, which primarily maintains distribution capacity for end customers. In such a market design, customers would be expected to contract with competing third-party energy-service providers (ESP), which provide actual energy services. Such a market structure allows competing firms to offer different terms of retail electricity service, which may include active demand-side management on the part of the ESP. Under such a market construct, ESPs may be provided with strong incentives (by the wholesale market operator) to, for instance, provide greater visibility into the availability and operation of distributed energy resources. A benefit of this market paradigm is that it allows retail competition to dictate the terms on which distributed energy resources are made available to the wholesale market operator.

5. Conclusions and Recommendations

The designs of electricity markets have been constantly evolving over the past thirty years. Largely, this evolution is driven by the need to refine market designs as flaws in and shortcomings of more rudimentary market models are identified. This is seen, for instance, in the evolution of restructured markets in the United States towards higher-fidelity representation of the transmission network.

Electricity markets are reaching something of a breaking point now, however. This is because the fundamental and underlying architecture of electric power systems are changing in major ways. Power systems no longer rely on a small number of large dispatchable generation resources. Rather, weather-dependent renewable generation that is subject to uncertain and variable real-time availability represents a growing share of the supply side. The demand side is no longer static and inflexible. The proliferation of distributed energy resources and novel uses of electricity create new challenges and opportunities for system operators to maintain supply and demand balance and reliable energy service.

This paper outlines some of the major lessons learned in this evolution of electricity markets and also lays out some design principles for electricity markets of the future. Importantly, we identify a number of outstanding research questions related to these design principles. This demonstrates that there are many unknowns regarding how markets of the future should be organized to operate and manage power systems of the future most efficiently.

To a large extent, the discussion in this paper focuses on wholesale market design. As such, it gives a slightly incomplete picture, because retail pricing and management of distribution systems are becoming increasingly important. There is a growing need to manage and coordinate the 'seam' between the distribution and transmission systems. Moreover, active customer and demand-side participation is crucially dependent on the design of innovative retail pricing structures, which do not exist in many parts of the world today. Market-design principle 6 touches on demand participation, but we do not consider this point in significant depth.

There are a number of competing visions for how the demand side can be better integrated into the market. One sees the utility or ESP serving this role. Another relies on load aggregators, which may be independent of the utility or ESP. Under such a paradigm, an aggregator may be responsible for managing the flexibility of one or multiple types of loads and offering those services into the market. A third possibility is to introduce distribution-level markets, which may be operated by distribution system operators. A hybrid design that combines these approaches may be prudent. An important related question is how to incentivize demand response from end customers. With the advent of market restructuring, there was an initial strong focus on using price signals (*e.g.*, real-time pricing) to incentivize more active demand management. Price-based programs may be less desirable if most of the demand response is expected to come from automated control systems. In such a case, direct control instructions (*e.g.*, from a utility, ESP, aggregator, or distribution system operator) may be a more efficient coordinating mechanism than relying on prices. Of course, an important question in pursuing such an approach is how to efficiently remunerate customers for the demand responsiveness that they provide. Our focus on wholesale market design in this paper should not be taken as suggesting that the demand side is unimportant.

Acknowledgments

The authors thank Armin Sorooshian and the editorial board for helpful discussions and suggestions. This work was supported by National Science Foundation grant 1548015. Any opinions and conclusions expressed in this paper are solely those of the authors.

Appendix A. Nomenclature

This appendix defines a number of terms that are used in this paper.

- **Marginal price:** the cost of producing one addition unit of a product—normally energy, reserves, or capacity in an electricity market.
- **Market-clearing price:** a price that 'clears' the market, in the sense that supply equals demand. Marginal prices are often used as market-clearing prices.
- **Locational marginal prices:** marginal prices that take network congestion (and its marginal-cost impact) into account. Locational marginal prices may vary from node to node in a network, if the network is congested of if losses are significant.
- **Producer revenue:** revenue earned by a producer, normally from the provision of energy, reserves, and capacity.
- **Producer profit:** the profit of a producer, which is defined as the difference between revenue and cost.
- **Producer welfare:** producer profit.
- **Demand utility:** 'value' that a demand obtains from consuming a commodity. In an electricity market, demand normally values the consumption of energy.
- **Demand payment:** what a demand pays to consume a commodity. In an electricity market demand may pay for energy, reserves, capacity, and distribution and transmission services.
- **Consumer welfare:** the net value that a demand obtains from consuming a commodity, which is defined as the difference between the demand utility and the demand payment.
- **Merchandising surplus:** the difference between demand payment and producer revenue.
- **Social welfare:** the total value that society gains from the transaction of a commodity between suppliers and consumers, which is defined as the sum of producer and consumer welfare and merchandising surplus.

References

[1] R. Raineri, Chile: Where It All Started, in: F. P. Sioshansi, W. Pfaffenberger (Eds.), Electricity Market Reform: An International Experience, Elsevier, 2006.

[2] U.S. Energy Information Administration, International Energy Outlook, DOE/EIA-0484 (2016) Edition (May 2016).

[3] T. R. Karl, J. M. Melillo, T. C. Peterson (Eds.), Global Climate Change Impacts in the United States, Cambridge University Press, 2009.

[4] K. Ardani, R. Margolis, 2010 Solar Technologies Market Report, Tech. Rep. DOE/GO-102011-3318, United States Department of Energy (November 2011).

[5] R. Wiser, M. Bolinger, 2015 Wind Technologies Market Report, Tech. Rep. DOE/GO-10216-4885, United States Department of Energy (August 2016).

[6] E. A. DeMeo, W. Grant, M. R. Milligan, M. J. Schuerger, Wind plant integration, IEEE Power and Energy Magazine 3 (2005) 38–46.

[7] J. C. Smith, M. R. Milligan, E. A. DeMeo, B. Parsons, Utility Wind Integration and Operating Impact State of the Art, IEEE Transactions on Power Systems 22 (2007) 900–908.

[8] E. A. DeMeo, G. A. Jordan, C. Kalich, J. King, M. R. Milligan, C. Murley, B. Oakleaf, M. J. Schuerger, Accommodating Wind's Natural Behavior, IEEE Power and Energy Magazine 5 (2007) 59–67.

[9] M. R. Milligan, K. Porter, E. A. DeMeo, P. Denholm, H. Holttinen, B. Kirby, N. Miller, A. Mills, M. O'Malley, M. Schuerger, L. Söder, Wind Power Myths Debunked, IEEE Power and Energy Magazine 7 (2009) 89–99.

[10] P. Denholm, M. O'Connell, G. Brinkman, J. Jorgenson, Overgeneration from Solar Energy in California: A Field Guide to the Duck Chart, Tech. Rep. NREL/TP-6A20-65023, National Renewable Energy Laboratory (November 2015).

[11] J. L. Sawin, F. Sverrisson, K. Chawla, C. Lins, A. McCrone, E. Musolino, L. Riahi, R. Sims, J. Skeen, Renewables 2014 Global Status Report, Tech. rep., Renewable Energy Policy Network for the 21st Century (2014).

[12] R. Sioshansi, Retail Electricity Tariff and Mechanism Design to Incentivize Distributed Renewable Generation, Energy Policy 95 (2016) 498–508.

[13] C. Weiller, Plug-in hybrid electric vehicle impacts on hourly electricity demand in the United States, Energy Policy 39 (2011) 3766–3778.

[14] R. Sioshansi, Evaluating the Impacts of Real-Time Pricing on the Cost and Value of Wind Generation, IEEE Transactions on Power Systems 25 (2010) 741–748.

[15] E. Ela, M. Milligan, A. Bloom, A. Botterud, A. Townsend, T. Levin, Evolution of Wholesale Electricity Market Design with Increasing Levels of Renewable Generation, Tech. Rep. NREL/TP-5D00-61765, National Renewable Energy Laboratory (September 2014).

[16] J. Bushnell, S. M. Harvey, S. Stoft, B. F. Hobbs, Final Opinion on Payment for Provision of Flexible Ramping, Tech. rep. (16 August 2011).

[17] B. Wang, B. F. Hobbs, A flexible ramping product: Can it help real-time dispatch markets approach the stochastic dispatch ideal?, Electric Power Systems Research 109 (2014) 128–140.

[18] V. Nanduri, T. K. Das, A survey of critical research areas in the energy segment of restructured electric power markets, International Journal of Electrical Power and Energy Systems 31 (2009) 181–191.

[19] P. N. Biskas, D. I. Chatzigiannis, A. G. Bakirtzis, European Electricity Market Integration With Mixed Market Designs—Part I: Formulation, IEEE Transactions on Power Systems 29 (2014) 458–465.

[20] P. N. Biskas, D. I. Chatzigiannis, A. G. Bakirtzis, European Electricity Market Integration With Mixed Market Designs—Part II: Solution Algorithm and Case Studies, IEEE Transactions on Power Systems 29 (2014) 466–475.

[21] Á. Sleisz, D. Raisz, Complex supply orders with ramping limitations and shadow pricing on the all-European day-ahead electricity market, International Journal of Electrical Power and Energy Systems 83 (2016) 26–32.

[22] F. Müsgens, A. Ockenfels, M. Peek, Economics and design of balancing power markets in Germany, International Journal of Electrical Power and Energy Systems 55 (2014) 392–401.

[23] G. M. Casolino, G. Liuzzi, A. Losi, Combined cycle unit commitment in a changing electricity market scenario, International Journal of Electrical Power and Energy Systems 73 (2015) 114–123.

[24] S. Stoft, Power System Economics: Designing Markets for Electricity, Wiley-Interscience, New York, New York, 2002.

[25] E. S. Amundsen, L. Bergman, N.-H. M. von der Fehr, The Nordic Electricity Market: Robust By Design?, in: F. P. Sioshansi, W. Pfaffenberger (Eds.), Electricity Market Reform: An International Experience, Elsevier, 2006.

[26] D. M. Newbery, Electricity Liberalization in Britain and the Evolution of Market Design, in: F. P. Sioshansi, W. Pfaffenberger (Eds.), Electricity Market Reform: An International Experience, Elsevier, 2006.

[27] A. Moran, The Electricity Industry in Australia: Problems Along the Way to a National Electricity Market, in: F. P. Sioshansi, W. Pfaffenberger (Eds.), Electricity Market Reform: An International Experience, Elsevier, 2006.

[28] J. Bowring, The PJM Market, in: F. P. Sioshansi, W. Pfaffenberger (Eds.), Electricity Market Reform: An International Experience, Elsevier, 2006.

[29] A. Goméz-Expósito, A. J. Conejo, C. Cañizares (Eds.), Electric Energy Systems: Analysis and Operation, Electric Power Engineering Series, CRC Press, Boca Raton, Florida, 2008.

[30] R. Sioshansi, S. S. Oren, R. O'Neill, Three-Part Auctions versus Self-Commitment in Day-ahead Electricity Markets, Utilities Policy 18 (2010) 165–173.

[31] S. S. Oren, A. M. Ross, Can we prevent the gaming of ramp constraints?, Decision Support Systems 40 (2005) 461–471.

[32] I. J. Pérez-Arriaga, C. Meseguer, Wholesale marginal prices in competitive generation markets, IEEE Transactions on Power Systems 12 (1997) 710–717.

[33] R. P. O'Neill, P. M. Sotkiewicz, B. F. Hobbs, M. H. Rothkopf, W. R. Stewart, Efficient market-clearing prices in markets with nonconvexities, European Journal of Operational Research 164 (2005) 269–285.
[34] R. Sioshansi, Pricing in Centrally Committed Markets, Utilities Policy 31 (2014) 143–145.
[35] S. S. Oren, Design of Ancillary Service Markets, in: Proceedings of the 34th Annual Hawaii International Conference on System Sciences, Maui, Hawaii, 2001.
[36] F. C. Schweppe, M. C. Caramanis, R. D. Tabors, R. E. Bohn, Spot Pricing of Electricity, Kluwer Academic Publishers, Norwell, Massachusetts, 1988.
[37] S. Borenstein, The Long-Run Efficiency of Real-Time Electricity Pricing, The Energy Journal 26 (2005) 93–116.
[38] S. Borenstein, S. P. Holland, On the Efficiency of Competitive Electricity Markets With Time-Invariant Retail Prices, The RAND Journal of Economics 36 (2005) 469–493.
[39] U.S. Department of Energy, Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them—A Report to the United States Congress Pursant to Section 1252 of the Energy Policy Act of 2005, Tech. Rep. LBNL-1252d, Ernest Orlando Lawrence Berkeley National Laboratory (February 2006).
[40] S. T. Lee, Z. A. Yamayee, Load-Following and Spinning-Reserve Penalties for Intermittent Generation, IEEE Transactions on Power Apparatus and Systems PAS-100 (1981) 1203–1211.
[41] L. Söder, Reserve Margin Planning in a Wind-Hydro-Thermal Power System, IEEE Transactions on Power Systems 8 (1993) 564–571.
[42] R. Doherty, M. O'Malley, A New Approach to Quantify Reserve Demand in Systems With Significant Installed Wind Capacity, IEEE Transactions on Power Systems 20 (2005) 587–595.
[43] M. A. Matos, R. J. Bessa, Setting the Operating Reserve Using Probabilistic Wind Power Forecasts, IEEE Transactions on Power Systems 26 (2011) 594–603.
[44] A. Papavasiliou, S. S. Oren, R. P. O'Neill, Reserve Requirements for Wind Power Integration: A Scenario-Based Stochastic Programming Framework, IEEE Transactions on Power Systems 26 (2011) 2197–2206.
[45] M. Vrakopoulou, K. Margellos, J. Lygeros, G. Andersson, A Probabilistic Framework for Reserve Scheduling and $N-1$ Security Assessment of Systems With High Wind Power Penetration, IEEE Transactions on Power Systems 28 (2013) 3885–3896.
[46] J. Warrington, P. Goulart, S. Mariéthoz, M. Morari, Policy-Based Reserves for Power Systems, IEEE Transactions on Power Systems 28 (2013) 4427–4437.
[47] J. M. Morales, A. J. Conejo, J. Pérez-Ruiz, Economic Valuation of Reserves in Power Systems With High Penetration of Wind Power, IEEE Transactions on Power Systems 24 (2009) 900–910.
[48] D. Bienstock, M. Chertkov, S. Harnett, Chance-Constrained Optimal Power Flow: Risk-Aware Network Control under Uncertainty, SIAM Review 56 (2014) 461–495.
[49] D. Bertsimas, E. Litvinov, X. A. Sun, J. Zhao, T. Zheng, Adaptive Robust Optimization for the Security Constrained Unit Commitment Problem, IEEE Transactions on Power Systems 28 (2013) 52–63.
[50] G. Pritchard, G. Zakeri, A. Philpott, A Single-Settlement, Energy-Only Electric Power Market for Unpredictable and Intermittent Participants, Operations Research 58 (2010) 1210–1219.
[51] F. Abbaspourtorbati, A. J. Conejo, J. Wang, R. Cherkaoui, Pricing Electricity through a Stochastic Non-Convex Market-Clearing Model, IEEE Transactions on Power Systems 32 (2017) 1248–1259.
[52] A. J. Conejo, F. D. Galiana, J. M. Arroyo, R. Garcia-Bertrand, C. W. Chua, M. Huneault, Economic Inefficiencies and Cross-Subsidies in an Auction-Based Electricity Pool, IEEE Transactions on Power Systems 18 (2003) 221–228.
[53] R. Sioshansi, E. Nicholson, Towards Equilibrium Offers in Unit Commitment Auctions with Nonconvex Costs, Journal of Regulatory Economics 40 (2011) 41–61.
[54] R. Sioshansi, W. Short, Evaluating the Impacts of Real-Time Pricing on the Usage of Wind Generation, IEEE Transactions on Power Systems 24 (2009) 516–524.
[55] M. Klobasa, Analysis of demand response and wind integration in Germany's electricity market, IET Renewable Power Generation 4 (2010) 55–63.
[56] K. Dietrich, J. M. Latorre, L. Olmos, A. Ramos, Demand Response in an Isolated System With High Wind Integration, IEEE Transactions on Power Systems 27 (2012) 20–29.
[57] E. Heydarian-Forushani, M. P. Moghaddam, M. K. Sheikh-El-Eslami, M. Shafie-khah, J. P. S. Catalão, A stochastic framework for the grid integration of wind power using flexible load approach, Energy Conversion and Management 88 (2014) 985–998.