Chapter 1
Overview of Wholesale Electricity Markets

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Abstract This chapter provides a comprehensive review of four key electricity markets:

- Energy markets (day-ahead and real-time markets).
- Ancillary service markets.
- Financial transmission rights markets.
- Capacity markets.

It also discusses how the outcomes of each of these markets may be impacted by the introduction of high penetrations of variable generation. Furthermore, the chapter examines considerations needed to ensure that wholesale market designs are inclusive of emerging technologies, such as demand response, distributed generation, and distributed storage.

This chapter is based on the overview of wholesale electricity market designs presented by Ela et al. [1, Sect. 2].

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1.1 Introduction

The goal of all electricity systems, whether they are operated by regulated monopolies or centrally administered by an independent system operator (ISO) or regional transmission organization (RTO), is to ensure the reliable delivery of electricity at the lowest cost to consumers. These goals are rooted in a long history of regulatory principles that influence the entry of new market participants, set prices, prescribe the quality and condition of entry, and obligate a utility to provide service. The rationale for this regulation emerges from the physical constraints of the electric grid. This chapter is not intended to explain the intricacies of the grid and electric utility regulation, but a brief review is important to understanding the challenges of electricity markets.

Three fundamental components comprise the wholesale electricity supply: generation, transmission, and coordination services. Each of these has a financial and physical component that must accommodate for the lack of a consumer response inherent to electricity markets while ensuring the constant balance of generation and load. Because of the extreme cost associated with failure of the power system, the physical requirements of the system must be ensured, even though market and operational inefficiencies are introduced to do so. Assuring this reliability requires procuring adequate generation, transmission, and coordination services. In short, resource adequacy—i.e., having enough available capacity in the system—is required to reliably meet load at all times. This includes adequate transmission capacity which is also required to ensure energy can be delivered to where it is needed. Because electricity demand is relatively inelastic, variable in time, and uncertain in quantity, both generation and transmission must be constantly coordinated to meet load in a reliable manner.

To gain the system requirements necessary to support the security and reliability of the electric grid, adequate market policies must be crafted that address the financial implications of these requirements. Ideally, these policies will provide sufficient opportunity for generators to recover both fixed and variable costs if they contribute to resource adequacy; promote the construction and upkeep of a viable transmission network; and incentivize generators to coordinate scheduling of resources to meet the variable and uncertain load while maintaining the reliability of the transmission network. Simultaneously, these policies must avoid incentivizing an overbuilt system or overcompensating inefficient units.

Electricity Industry in North America. Historically the electricity industry in North America has been operated as a natural monopoly, regulated by a combination of state commissions and Federal oversight for some aspects of interstate trade. The legal justification for electric utility regulation in the United States can be traced through British common law and a series of Supreme Court cases.[1] Generally speaking, these cases have found that utilities, such as those in the electricity and natural gas

[1]Munn v. Illinois (94 U.S. 113, 1887), Smyth v. Ames (169 U.S. 466), and Federal Power Commission v. Hope Natural Gas Company (320 U.S. 591).

industries, provide services that are in the "public interest" and are necessary for the common welfare of the people. The economic justification for regulation has been focused on the inherently noncompetitive nature of the market. The market can be uncompetitive for a variety of reasons, including: (1) technology that allows a limited number of companies to provide adequate capacity to supply all demand; (2) the unique position of a principle buyer; and (3) conditions in the market that do not produce competitive results [2]. Because of these characteristics, regulators and policy makers have adopted certain regulatory frameworks to meet the essential needs of society and to ensure that utilities are capable of earning a fair return on their investments. However, the potential benefits of competitive generation instigated the restructuring of the electricity markets in the late 1990s. Currently, more than two thirds of the electricity consumption in the United States is purchased within restructured electricity markets. The restructured markets have been designed to support the financial constraints of generation, transmission, and coordination that are necessary to secure a stable and reliable physical power system while addressing the problems of inefficient pricing, investment risk, and market power.

In the United States, RTO/ISO administered markets have evolved in similar directions to a large extent following the principles proposed in the standard market design [3]. This design reflects a pool-based market in which there exists a two-settlement system for day-ahead markets (DAMs) and balancing/real-time markets (RTMs), with co-optimized energy and ancillary services, locational marginal pricing (LMP) for energy, and financial transmission rights markets (FTRs) in place for financial hedging. Energy is sold in forward (e.g., day-ahead, hourly) markets and balanced in 5-min RTMs with LMPs. Locational energy markets in the United States are cleared once a day for hourly trading intervals for day-ahead markets and every 5-min for real-time markets. At present, ancillary service markets are in place in all markets, including those for spinning contingency reserve, nonspinning contingency reserve, and regulating reserve. The ancillary service markets operate in a similar manner to energy markets and are cleared using the same model, with day-ahead and real-time prices and schedules for the capacity reservation of the ancillary service. FTRs are cleared in forward markets and are an instrument put in place to hedge against locational differences in energy prices.

Each regional transmission organization/independent system operator also has a process for procuring sufficient resources to meet the peak load requirements. In the Pennsylvania-New-Jersey-Maryland Independent System Operator (PJM), New York Independent System Operator (NYISO), and the Independent System Operator of New England (ISO-NE), mandatory capacity markets have been designed to incentivize investment in installed capacity and to allow peaking units to recover fixed costs. At present, the Electric Reliability Council of Texas (ERCOT), California Independent System Operator (CAISO), Midcontinent Independent System Operator (MISO), and Southwest Power Pool (SPP) do not have mandatory capacity markets available and utilize various administrative processes and spot (scarcity) prices to provide fixed-cost recovery for resources.

Europe. In Europe, most markets offer day-ahead and intraday markets. The power systems and energy markets are operated separately; the market clears a dispatch order, which then can be adjusted to accommodate transmission constraints. Germany, for example, with its extensive bilateral market contracts, requires longer gate closures to allow the transmission system operator (TSO) to conduct load-flow calculations and coordinate with neighboring TSOs, which in turn requires significant re-dispatch to resolve transmission constraints [4].

In the Nord Pool Spot, there is a day-ahead market followed by an intraday market, which matches bids continuously until one hour before the hour of delivery. This decreases liquidity in comparison to the Iberian intraday market, which has sessions that concentrate the trades. The Iberian intraday market, however, has a longer delay between the trade and delivery. Consequently, in Nord Pool there is no need for a market between the intraday and tertiary regulation market, which is called the regulating power market in Nord Pool (and the real-time market in the two-step markets). Nord Pool's regulating power market requires activation in 15 min and also is used to meet operating reserves.

1.2 Energy Markets

As discussed in the previous section, energy is bought and sold in most US and European markets through a two-settlement system. A forward market sells energy to load-serving entities (LSEs) and buys from sellers in advance of the time when the energy is produced and consumed. This is typically through the day-ahead market (DAM). The DAM clears to meet bid-in load demand for the entire day, one day in advance. Schedules and prices are calculated from the market-clearing engine, and this price-quantity pair is settled for all market participants regardless of their actual performance. The DAM is important because it provides a hedge against price volatility in the real-time markets caused by load forecast errors, generator outages, or other imbalances. The DAM also allows for make-whole payments when resources do not recover their costs, and it provides price incentives in advance toward reliable operation when resources may need ample notification time to be able to start their generating resources [5]. To reflect changes that may occur between the day-ahead market and real-time operations, a second market clearing is used by RTOs/ISOs to re-dispatch resources and commit new resources to meet system requirements. This is generally referred to as the RTM. Variability and uncertainty is present throughout the power system including changes in weather that can cause unexpected deviations in load and variable resource output, and forced outages that can take resources and network facilities offline unexpectedly. The RTM is in place to set prices and schedules to match the imbalances caused by such events. It reflects the actual operation of the resources participating in the market. Many markets also have intermediate scheduling procedures on the hour ahead or a few hours ahead to facilitate this process in advance of real time when the differing conditions from the

DAM are apparent. These markets typically have advisory prices and schedules, but they may have binding commitment directions.

In both day-ahead and real-time markets, suppliers will offer energy bids as a price and quantity pair. In US markets, there is further complexity in supplier offers, which are designed as three-part bids. Due to the non-convexity of costs of many generating resources, the generators submit a bid for (1) incremental energy, (2) no-load cost—i.e., a cost just to be online, or at its minimum generation level, and (3) a cost of starting up the generating unit and synchronizing it to the grid. The generators also submit to the ISO their unit constraints, including how fast they can ramp, how long they must stay online if committed, and other constraints. The market operator will select the least-cost set of suppliers to meet the demand based on these three-part bids and generating unit constraints while also obeying many of the physical power system constraints.

It is important that the average prices of the day-ahead and real-time markets converge, so that market participants should not have a strong preference to be in either market. Virtual trading, or convergence bidding, is used in most RTO/ISO markets to ensure that the prices of the DAM and RTM converge to the same price on average [6]. Virtual traders will sell or buy energy in the DAM and buy or sell it back in the RTM. They have no requirement to have physical assets to supply or consume energy. By taking advantage in either market when there is a premium in one, they will drive down the difference in prices between these markets. This design feature of the market recognizes the natural tendency of traders to arbitrage across different markets. In the absence of virtual trading, there is potential for a premium in one market that can lead to uncompetitive and inefficient behavior.

In addition to the day-ahead market process, a subsequent process is used, generally referred to as the reliability unit commitment (RUC) process. The day before the operating day, an initial security-constrained unit commitment (SCUC) will solve to meet the bid-in load with bid-in generation and create the schedules and prices for the DAM. These bid-in quantities, in particular the bid-in load or bid-in variable generation capacity, may or may not be close to reality. To ensure the system has sufficient capacity available, a subsequent SCUC will be solved to meet the RTO/ISO forecasted load. The exact practices vary by region, but generally the RUC will only commit additional resources and will not decommit any resources needed in the DAM. For example, while most markets solve the RUC subsequent to the DAM, the NYISO solves the DAM and RUC iteratively, so that resources committed by the RUC can affect the DAM prices and schedules [7]. Most ISOs are now also using the RTO/ISO forecasted variable generation as part of the RUC process as well. Energy markets that consist of short-dispatch intervals (e.g., 5-min dispatch intervals), which already have been adopted in many restructured markets, improve system flexibility by more closely matching the changes in variable generation (VG) and load ("net load") economically. As net load changes, the dispatch optimization responds as well-cost-effectively optimizing generation. Short-dispatch interval markets also reduce the required levels of regulating reserves needed, which are the automatic resources that can respond to minute-to-minute fluctuations and are the most expensive ancillary service [8]. High energy prices during the ramp periods also could provide an incentive for flexible supply. All generation receives the energy market clearing price in an energy market, as opposed to markets with ramp products, described below. A two-step market with unit commitment in the day-ahead timescale will leave significant forecast errors to be resolved during real-time balancing. The balancing resources acting on the timescale of a few minutes can be relatively expensive [9]. An alternative is to have some form of intraday market that enables participation from power plants with intermediate lead/start-up times [10].

For example, the Iberian market already has a considerable share of variable generation. The market structure consists of a day-ahead market followed by six sessions in the intraday market. The gate closure in the intraday market is 3 h and 15 min. The intraday market is at times followed by a deviation management market, which is used when a deviation of more than 300 MWh is expected to last several hours. A tertiary regulation market is used to recover secondary regulation reserves in the intra-hour timescale. In the Nord Pool Spot, there is a day-ahead market followed by an intraday market, which matches bids continuously until one hour before the hour of delivery. This decreases liquidity in comparison to the Iberian intraday market, which has sessions that concentrate the trades. The Iberian intraday market, however, has a longer delay between the trade and delivery. Consequently, in Nord Pool there is no need for a market between the intraday and tertiary regulation market, which is called the regulating power market in Nord Pool (and the real-time market in the two-step markets). Nord Pool's regulating power market requires activation in 15 min and also is used to meet operating reserves.

Ramp products, akin to proposals for flexible ramping and ramp capability products in the CAISO and MISO markets, respectively, are designed to periodically complement the fast energy market by providing for operational flexibility to meet load more reliably and efficiently, as well as incentivizing the specific resources that provide the flexibility to do so. The ramp product market price can have supplemental payments that are provided only to those resources providing the ramping support. Ramp products therefore reward only the flexible generation and, during these flexibility-scarce periods, do not reward inflexible resources. The ramp capability price would be zero during most hours, when ramping capacity in the energy dispatch mix is sufficient to follow load [11]. When ramping is needed whether due to expected variability, or uncertainty in meeting the net load in future intervals and not provided by the energy market, the price would reflect the marginal cost of providing that ramping capability, incentivizing flexible resources.

To add ramp capability and ensure sufficiently fast response, the Spanish TSO in May 2012 implemented a new market for the management of additional upwards reserves [12]. EirGrid, the TSO in Ireland, also has proposed a new ramping product to respond to imbalances that occur over the minutes-to-hours timeframe, such as from changes in demand, wind generation, and interconnector flows. The TSO anticipates a broad range of resources to supply this service, including wind and photovoltaic (PV) plants that have been dispatched down, conventional generators, storage, and demand [13]. Negative pricing can occur when serving the next increment of demand would actually save the system money; that is, the marginal cost to serve load is negative. For example, negative pricing can occur due to a lack of flexibility within the system.

This might be due to limited transmission capacity creating location-specific negative pricing, minimum generation periods during which resources cannot be shut down, and other reasons. Negative prices also can occur during periods of high variable renewable energy generation and low loads. In general, this can happen either due to resources setting the price with negative cost offers (e.g., due to production credits), or because of reduced capability to reduce generation and increase load (e.g., due to self-scheduled resources). Incorporating negative pricing into market design facilitates balancing and provides a financial incentive to increase system flexibility for several reasons:

- Negative pricing can discourage generators, such as wind (unless tax incentives encourage production), nuclear, and coal from providing too much power when demand is low.
- Negative pricing sends a strong signal to generators to be more flexible and reduce constraints on flexibility. In Denmark, the minimum running capacity of some older coal-fired power plants has been reduced from 30 to 10% of maximum capacity due to dynamic and negative pricing [14].
- Negative pricing can encourage greater diversification in the location and types of variable renewable energy, especially in transmission-constrained areas.
- Negative pricing can encourage the use of storage to absorb excess production, and load to increase demand.
- Negative pricing can provide a transparent mechanism for curtailment of renewable resources via market means rather than out-of-market procedures.

One concern about negative pricing in the United States is that with the production tax credit—which in 2013 offers wind generators a $0.023 subsidy for each kilowatt-hour of energy produced—wind energy can still generate revenue when prices have become negative. They then can offer negative prices representing this“effective”cost of generating. This subsidized bidding can distort the clearing price and impact the rest of the generation fleet. A second concern with negative pricing is that it makes revenue streams more difficult to calculate, and therefore can deter investors from participating in energy markets.

When implementing negative prices, it is important for markets to coordinate with neighbors with respect to the use of administratively defined minimum price levels. At present these minimum price levels differ, for example, between Germany and Denmark, where flows from Germany to Denmark have been observed when Danish prices were negative and extra power was not needed, but German prices were even more negative. For example, this occurred in December 2012, when Danish bids were curtailed to achieve market equilibrium above the minimum price level, but even cheaper German power was imported anyway. Currently, measures are under consideration to avoid this occurrence in future. As already occurs in Denmark, individually negotiated compensation for offshore plants could be designed to eliminate fixed feed-in compensation during hours of negative prices to relieve stress on the power system.

1.3 Ancillary Service Markets

Ancillary services are used to support power system reliability and perform the necessary services that the energy market cannot provide [15]. In the United States, all transmission providers are required to procure ancillary services. The six required ancillary services were defined by the Federal Energy Regulatory Commission's (FERC) landmark rule, Order No. 888 on "Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities: Recovery of Stranded Costs by Public Utilities and Transmitting Utilities" [16]. The functional unbundling of these services was deemed necessary by FERC to ensure that transmission access could be provided in an open and transparent manner. Although the requirement to procure and provide these services is consistent across all wholesale markets, the method of acquisition varies greatly. In non-RTO/ISO regions, these services are obtained and paid for according to a series of FERC-approved rate schedules. In the RTOs/ISOs, most of these services are procured in a competitive manner that is co-optimized with energy markets.

Although much research has focused on how variable renewable resources could increase the need for ancillary services, variable renewable resources also can be used to provide these ancillary services [17–19]. Currently, rules do not allow this provision in most of the ancillary services markets. In Germany, auctions for frequency control reserves occur six days in advance, which effectively precludes wind energy from bidding due to forecasting uncertainties [20]. Variable generation, however, can provide great flexibility. Variable renewable generators can have fast electronically controlled ramp rates, zero minimum generation levels, and no start-up time needs. With increased penetrations, it might be more economical to utilize variable renewable resources to provide these services for both consumers (in terms of reduced production costs) and for variable renewable generators (in terms of increased profits). Kirby et al. [21] describe the provision of ancillary services in some markets by demand response.

Demand-side resources increasingly are providing ancillary services to the grid, in roles that require faster and more verifiable performance than traditional uses of energy efficiency. Demand-side resources long have been employed in ways that only require several hours of lead time, such as "interruptible load" for emergency peak shaving [22] or to increase nighttime load during off-peak price periods. Yet, provision of ancillary services occurs on much shorter timescales, typically seconds to minutes. Such fast-acting demand response is employed in several US wholesale markets including ERCOT, PJM, and MISO [22]. System security requires that such systems ensure rigorous performance characteristics (response time and minimum load size), special contractual and compensation mechanisms, robust measurement and verification methodology, and high-speed communications interface to enable automatic control. As such, industrial sources have predominated in providing ancillary services. Pilot and demonstration projects are underway to aggregate residential and commercial resources to provide ancillary services [23], but significant legal and technical barriers remain to ensure adequate performance characteristics.

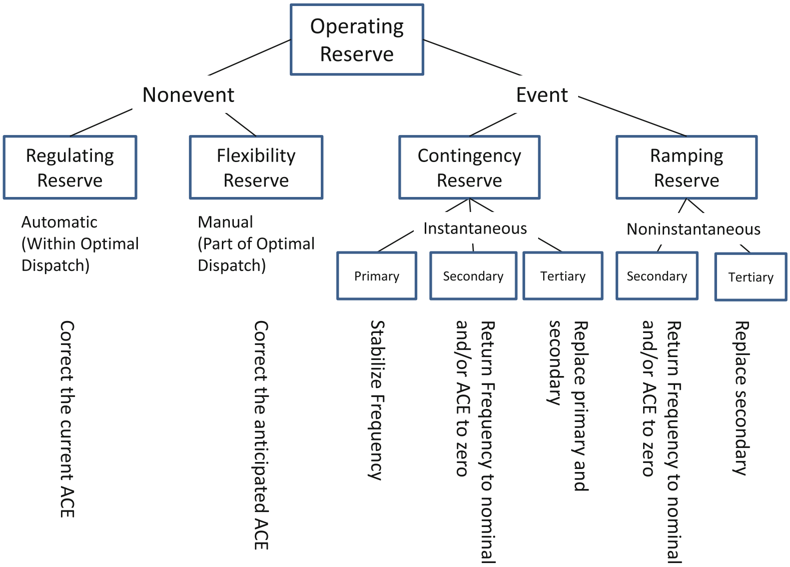

Fig. 1.1 Operating reserve types and their uses [15]

In previous literature, we categorized all active power control services that are ancillary to energy scheduling, also defined as operating reserve, as shown in Fig. 1.1 [15]. The operating reserve types that have existing dynamically priced markets—including synchronized reserve (contingency reserve-secondary), supplemental reserve (contingency reserve-tertiary), and regulation (regulating reserve)—are bought and sold in day-ahead and real-time markets in a similar manner to energy markets. In fact, the US markets that have ancillary service markets currently co-optimize energy and operating reserve when clearing DAM and RTM markets. This means that the markets are cleared simultaneously so that costs and requirements of both markets are considered when clearing the entire market.

Other ancillary services are not sold through dynamic markets. For example, reactive supply and voltage control are needed services both during steady state and disturbances. Reactive power, which supports voltage control, does not travel far due to high inductive impedances. It therefore is very localized which, in turn, inhibits a broad competitive market. In general, all generators except wind plants are required to be able of providing reactive power within a power factor range defined in their interconnection agreement, although in Spain new operating procedures are being studied to require wind turbines to provide voltage control [24]. Compensation for provision of this service varies by transmission provider. In US, there is no requirement to compensate generators for reactive power within the power factor range unless the transmission provider is compensating its own generators. Generators typically are paid for fixed costs as well as opportunity costs; that is, any costs it foregoes in the markets because of constraints on providing reactive power [25].

Other services are much more long term and are cost based. For example, black-start service is needed from generators for system restoration following blackout events. These resources must be capable of starting without outside power supply, able to maintain frequency and voltage under varying load, and able to maintain rated output for a significant period of time (e.g. 16 h) [26, 27]. Many markets will request black-start service proposals and will then have cost-based recovery mechanisms in place for these resources. Other services such as primary frequency response and inertial response currently lack markets or cost-based recovery mechanisms in many markets, which was detailed in [11].

Variable renewable energy lacks inherent inertial response, which helps the system remain stable in the initial moments after a disturbance, before the automatic response by governors. Simulations by the Western Electricity Coordinating Council have shown that frequency response degrades during periods of high wind and low load, when conventional generators comprise a small share of the dispatch mix [11]. The simulations also show that it is technically possible for wind to sufficiently emulate this inertial response by connecting to a power electronic converter; some load and storage also can supply similar capability. Inertia is an inherent part of synchronous generation, therefore it has no added cost other than being online, and so a market similar to the other ancillary service markets, with changing schedules and prices, might not be the best approach. If some resources do provide the service, and others do not, however, then some sort of compensation might be required.

Flexibility reserve, for additional ramping requirements to meet increasing levels of variability and uncertainty, have historically not been an ancillary service market either, but are garnering more interest in some markets.

1.4 Pricing Energy and Ancillary Services

Prices for energy and ancillary services are calculated in similar ways throughout all of the restructured regions in the United States. In US markets, these prices are based on the marginal pricing concept, in which the prices are equal to the bid-based marginal cost to provide each service. Market participant bids are meant to reflect true variable costs, and the marginal pricing design theoretically drives resources to bid their true variable costs. We refer to these prices as LMP and ancillary service clearing prices (ASCPs) for energy and ancillary services, respectively.

Ancillary service markets will also typically follow a pricing hierarchy [28]. The hierarchy will price higher quality reserve services that share the same capacity to be greater than or equal to the lower quality service. This is because some ancillary services are more critical than others, and the incentives provide transparency to market participants on which service they should provide. ASCP may also have locational differences when deliverability issues arise.

Most ASCP payments go to market participants for the provision of capacity to provide ancillary services. The payments usually are not modified based on how the market participant performs the ancillary service, or if the unit was even asked to respond, as long as its performance is satisfactory and the capacity reservation is held (although if deployed, the resource will be paid for the energy deployed with additional energy payments). Recently, there has been motivation to incentivize market participants based on how they performed. FERC Order 755 directs a pay-for-performance scheme for regulating reserve. Resources that provide greater movement and accuracy when providing regulating reserve are compensated more. This is an advantage for participants that can provide regulating reserve faster or more accurately.

Suppliers will be paid the DAM LMP at the DAM energy schedule and the DAM ASCP at the DAM ancillary service schedule. When asked to provide energy or ancillary services differently from the DAM schedule in the RTM, the suppliers will be paid the RTM LMP and RTM ASCP for the difference between the RTM—and DAM—scheduled energy and ancillary services, respectively. In both markets, load pays the LMP and generation is paid the LMP at their corresponding locations. The prices in RTM can change because of changing load, changing VG output, change in committed resource, or change in network topology (i.e., due to transmission outage). The change in RTM prices should incentivize suppliers to adjust schedules accordingly. The introduction of virtual trading (i.e., convergence bidding) should result in the average prices between DAM and RTM to converge, thereby not leading to suppliers, or consumers, to prefer one market than another.

Another important factor to the pricing of energy and ancillary service prices is the administratively-set scarcity prices. Scarcity pricing implies that when demand is very high, the supply may be insufficient and/or costly to deploy to meet the load [5, p. 70]. These price spikes reflect the relative inelasticity of supply (and demand) at high load levels or due to other sources of capacity constraints. Scarcity pricing can be designed to encourage investments in flexible response, such as storage and price-responsive load, because these resources can respond quickly to brief periods of scarcity. Scarcity pricing is favored in some markets on the basis that policy interference in pricing mechanisms, such as through a capacity market, would jeopardize market participants' trust in the market and discourage investors from investing in new capacity.

These pricing methods are designed to incentivize resources to offer their true costs for energy and true capabilities for ancillary services. The RTO/ISO is responsible for solving an optimization problem to minimize the total costs to meet the energy and ancillary service demands while also meeting numerous generation and reliability constraints. This schedule should place each market participant in a position to make the most amount of profit given the prices generated by the market-clearing engine. However, because of issues such as non-convex costs and commitment constraints, it is possible for the RTO/ISO to direct a market participant to provide energy and ancillary services that cause that market participant to lose money. When this happens, the RTO/ISO provides a make-whole payment to ensure that the market participant does not receive a negative profit. After actual power data is measured, resources are paid this make-whole payment in addition to the scheduled payments. Sometimes penalties are in place for market participants that stray too far from their directed energy or ancillary service schedules. These vary depending on the market region but give further incentives to ensure reliable operation.

Scarcity pricing predominantly is found in the European Union, where the policy goal in several states has been to combine scarcity pricing with carbon prices to increase the competitiveness of low-carbon flexible units and use extensive interconnections to balance integrated regions. Nevertheless, the European Union reflects different policy approaches to adequacy, and member state policy actions have yet to create a coordinated market-based approach. The differing approaches to adequacy have complicated cross-border trades, such as those between countries with and without capacity payments [29].

1.5 Financial Transmission Rights Markets

FTR markets, also called transmission congestion contracts and financial congestion rights, are markets designed to hedge the volatility in locational differences of energy pricing [30]. When the transmission system is congested, the load at the receiving side of the constraint would typically pay more for energy than the generators supplying energy at the sending side. This difference is allocated to the FTR holders between the two locations. These FTRs are not part of system operation, because they are purely financial and do not affect the objective of the system operator to dispatch the supply at least cost. Bilateral agreements between supply and demand at different locations can avoid the volatility of pricing between their locations with the purchase of FTRs.

Market participants can obtain FTRs through an RTO-specific allocation process and auctions. Initial FTR allocations are based on historical usage and entities that fund the construction of new facilities. FTRs are typically auctioned at annual, seasonal, and monthly periods. They can also be traded bilaterally. Each auction can include new potential buyers and sellers of FTRs, and it will include a market-clearing engine similar to the one used in the energy market, in which the objective is to minimize the cost of all FTR bids while incorporating the network security constraints. The pricing that results from the FTR auction is performed in a very similar manner to the prices of energy, where in this case the marginal cost of transmission is paid to the seller and taken from the new buyer. Many other characteristics can be included in the FTR market [31]. FTR options are rights in which the owner earns only the locational difference in energy prices if that difference is in their favor. Some markets will have FTRs that are different for on-peak and off-peak periods to signify the differences in transmission flows between these periods. Other areas also have multi-round auctions, in which each round will sell only a portion of the available transmission capacity to FTR purchasers. This is said to make the FTR market more flexible and competitive and allows for the market participants to adjust the bids each round after learning the results from the previous round.

The revenues that FTR holders receive when they own the rights are typically through the congestion costs that occur in the DAM rather than the RTM. The more the prices differ between the DAM and RTM, the more that FTRs may not reflect the true cost of congestion. The congestion patterns are well understood in most markets, although on-peak and off-peak times and transmission outages can certainly affect the outcomes differently than anticipated during the auction periods. Also, at the onset of FTRs it was thought that they could promote future investment in new transmission, but there is a lot of argument about whether FTRs provide sufficient incentives for transmission investment [32]. How these markets may evolve in the future is still very unclear, as is the impact that higher penetrations of VG have on them. However, the scope of this chapter (and book) has only marginal relevance to FTR markets and so we provide little focus on this market product.

1.6 Capacity Markets

Capacity markets are motivated by the desire to employ a market mechanism to ensure that new generation is developed on time to meet resource adequacy targets and help these resources recover their capital costs. Power plants are large, capital-intensive resources that take considerable time to permit and build. The decision to build a power plant must be made well before the plant is needed. Some RTO/ISO regions rely on high and volatile energy prices that are sometimes constrained by administratively-set scarcity prices or price caps. Other RTO/ISOs operate explicit capacity markets to ensure that sufficient generation will be available to meet the expected load. In vertically integrated systems, resource adequacy assessments are carried out by the utility, and any needed additional capacity could be acquired internally or via contract, subject to regulatory oversight. The costs for procuring that capacity are typically subject to rate-making proceedings with state public utility commissions.

Mandatory capacity markets are intended to address long-term reliability needs and ensure that resources have adequate opportunity to recover their variable and fixed costs over time. Capacity markets are often backstop mechanisms that evaluate potential capacity shortfalls after considering bilateral contracts or other power purchase agreements [33].

In Europe, the question of capacity remuneration mechanisms is discussed very differently among the Member States. Conventional power plants (even new flexible gas plants) are being closed or are threatening to close not only because some are at the end of their lifetimes, but in some cases because of changes in fuel prices. As a result, generation adequacy regionally is becoming a matter of concern [4, 29, 34]. Also, limited interconnection capacity, for example in countries such as Spain, has increased interest in capacity payments. In Europe, security of supply is a national question, but over-capacities would occur if solved strictly nationally. Thus, European organizations and associations strongly recommend international coordination [35–38].

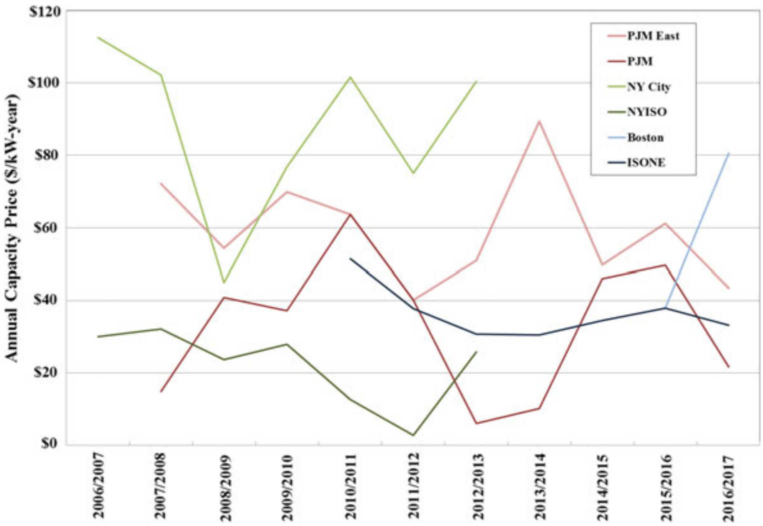

Fig. 1.2 Capacity prices in some RTO/ISOs (adapted from [40])

In the United States, the methods for calculating capacity prices in each of the RTO/ISOs are based on the market design choices of each region. In general, regions with capacity markets find that the capacity prices tend to be limited to the capital cost of a new gas-fired plant that can be sited and built within three years [39]. As shown in Fig. 1.2, prices generated by mandatory capacity markets have been considerably volatile [40]. These results are driven by a variety of market considerations that vary from one region to another.

The demand for capacity is based on an administrative process that determines the total amount of capacity necessary to meet peak load requirements. NYISO, PJM, and ISO-NE all use a downward-sloping demand curve for capacity rather than a fixed target. The downward-sloping demand curve is constructed to reflect the marginal value of capacity to load, and it serves to reduce the potential exercise of market power in capacity auctions. Although the specific demand curve parameters vary between the markets, the main principles are illustrated in Fig. 1.3. The curve is constructed around a target for new capacity at which the price is set equal to the cost of new entry (CONE). The cost of new entry is typically set equal to the annualized capital cost of a new peaking plant (e.g., a combustion turbine), and it may be adjusted for the expected revenue from the energy market (i.e., net CONE). Administered price caps are common and are designed to protect against potential market power and provide a backstop mechanism in case insufficient bids are received from the market.

Resources participating in the capacity markets must verify their capabilities to determine the total capacity they can bid into the market. Each of the mandatory capacity markets has a process for qualifying as a capacity resource. Generally speaking, resources interested in participating in capacity markets must verify their

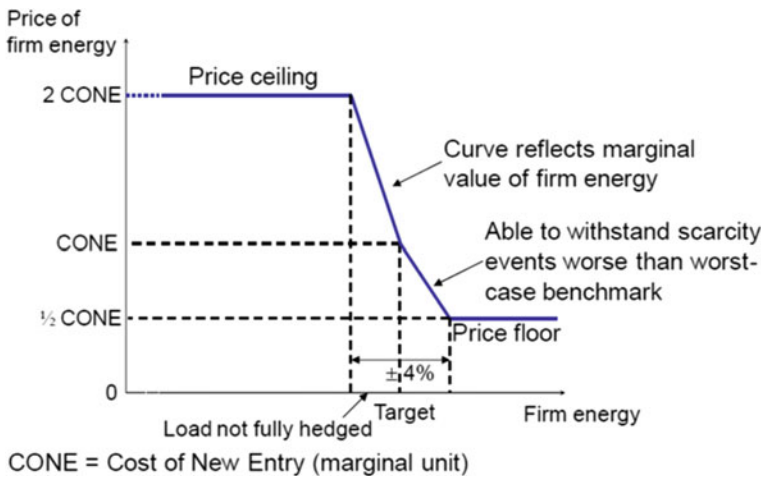

Fig. 1.3 Illustration of demand curve for capacity (based on [41])

operating capability in MW for a specified time period, usually the winter or summer peak. Each organized market has different capacity qualification rules for existing resources, new resources, external resources, demand response, and renewables. Many of the markets will require capacity market resources to offer their capacity in the day-ahead market. Current capacity markets typically do not require capacity resources to have specific attributes other than the provision of capacity during periods of peak demand.

The physical location of a resource is also important for capacity markets. Transmission limitations can limit the ability of a load to access a resource. Local capacity obligations are enforced in each of the markets to ensure that load-serving entities have adequate supply and transmission capacity to deliver energy to an area. The issue is most prevalent in regions with constrained export and import capabilities. Accurately identifying zones that have deliverability constraints is critical to developing efficient capacity markets.

There is no widespread agreement on the need for a capacity mechanism to supplement energy-only markets—and, if the need exists, how best to do it. There also is little, if any, evidence regarding whether scarcity pricing would result in revenue sufficiency for capacity, as illustrated by the current review of options in ERCOT [42]. Because most retail consumers do not see real-time prices that reflect cost, the demand curve for electricity is muted [5, 43]. Proponents for capacity mechanisms argue that this malfunction of the market for electricity, coupled with the lack of ability to differentiate reliability among customers on a widespread basis, renders an energy-only market incapable of providing sufficient forward capacity [41]. This debate is not new, and began long before variable renewable energy sources were significant in the electricity supply.

1.7 The Impacts of Variable Generation on Market Outcomes

The outcomes of each of the markets discussed above may be impacted by the introduction of high penetrations of VG. Possible impacts are briefly discussed in the list below.

- Energy markets:
  - VG can reduce average LMPs because of its low variable costs.
  - VG can cause more occurrences of zero or negative LMP periods because of its variable cost and zero or negative bid-in costs.
  - VG's increased variability can cause LMPs to be more volatile from one time period to another.
  - VG's increased uncertainty can cause greater differences between DAM and RTM LMPs (although on average they are likely to remain converged as a result of virtual trading).
  - VG can cause a greater need for flexible resources in the energy market, and the energy market may or may not provide sufficient incentive for this flexibility.
- Ancillary service markets:
  - VG can increase the requirements for normal balancing reserve, such as regulating reserve, which can increase the ASCP for those services.
  - With higher balancing reserve demands and increased variability and uncertainty, administratively-set scarcity ASCP may be triggered more often, resulting in more frequent extreme price spikes.
  - VG can displace synchronous, frequency-responsive resources, and when not equipped with technology to provide a comparable response, it can cause the need for supplemental actions or market designs to ensure that sufficient frequency response and/or system inertia is available.
  - VG can cause the ancillary service requirements to change from one day to another and from DAM to RTM, if the requirements are based on correcting the variability and uncertainty of VG, which can cause uncertainty in ancillary service demands and changing demands for the same time periods between DAM and RTM, similar to load.
  - VG can cause a need for greater flexibility from the resources that correct for its variability and uncertainty. Certain forms of flexibility may or may not be built into the current ancillary service markets.
- FTR markets:
  - VG's increased variability and uncertainty can cause greater variation on power flow, which causes FTR holders to be uncertain about expected congestion patterns.
  - VG's increased uncertainty can cause greater deviations of power flows between DAM and RTM. Because FTR revenues are typically based on the DAM, there

could be greater divergence between FTR revenues and actual congestion patterns.

- Capacity markets:
  - The reduction in LMP and energy schedules from conventional resources will result in reduced revenues in the energy market. If these resources are still required to be available for short periods of time, more resources become capacity-based rather than energy-based.
  - VG's variability and uncertainty can cause the need for different types of resources to be built and available. In other words, it might require the need to plan and build more flexible resources to prepare for future needs and not to focus on the need for MW capacity alone.
  - VG's variability and uncertainty can cause the need for existing resources to modify their flexible capability potential. Market designs may need to incentivize the existing resources to spend the capital on retrofits to increase the flexible capability that it can provide.
  - Must-offer price rules, designed to limit the ability of buyers to suppress capacity prices by subsidizing relatively higher-cost new capacity to replace lower-cost existing capacity, may increase risk that a resource built to satisfy a state renewable portfolio standard will not clear the capacity market at the applicable minimum offer floor.

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