Handbook on the Economics of Electricity

Chapter 7: Strengths and Weaknesses of the PJM Market Model

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November 26, 2019

1. Introduction

PJM Interconnection enjoys iconic status as a major innovator in electricity restructuring. Building on its long history as a major power pool, PJM demonstrated the capability to provide the necessary coordination for competition in electricity markets. The core of the PJM market design, a bid-based-security-constrained-economic-dispatch-with-locational-marginal-prices (BBSCEDLMP) model, works in theory and in practice. It is the only electricity market design that integrates engineering and economics to support efficient markets under the principles of transmission open access and non-discrimination. This market design was eventually adopted in every organized wholesale electricity market in the United States. Development of this market followed a process combining analysis, experimentation, and learning. The evolutionary process continues to meet new challenges.

2. Brief History of the PJM Wholesale Power Pool

Electric utilities started out local, typically in a single city, and grew. Given the variability of electric load and the diversity of generating plants, it became the norm for interconnection arrangements to share generating, transmission and other resources. The power pool called the Pennsylvania-New Jersey Interconnection began in 1927 when Public Service Electric and Gas Company, Philadelphia Electric Company, and Pennsylvania Power & Light Company agreed to pool their resources, in what would become the wholesale bulk power market, and dispatch electric generating plants on a lowest cost basis, thereby producing shared savings.[1] Subsequently, Baltimore Gas and Electric Company and General Public Utilities joined in 1956, and the name was changed to the Pennsylvania-New Jersey-Maryland Interconnection, or later the PJM Interconnection.

The slow pace of expansion continued with the addition of other utilities in New Jersey, Maryland, the District of Columbia and Delaware, eventually reaching a relatively stable configuration in 1981. The pace of development accelerated after passage of the U.S. Energy Policy Act of 1992 (EPAct92). This seminal legislation broadened the scope of wholesale market competition and presented new challenges that strongly favored expansion and reform of regional power pools.

1 Unless otherwise noted, the historical information is from "PJM History" at www.pjm.com.

The Federal Energy Regulatory Commission (FERC) encouraged these efforts to build on power pool operations and in 1997 approved PJM as the first fully functioning Independent System Operator (ISO) in the United States. This later transformed into its status as the first Regional Transmission Organization (RTO) in 2002.

The events and key decisions that accompanied reformulation of the functions of the RTO in PJM are important, as discussed below. One of the major impacts was the move to expand the footprint of PJM and the coordinated wholesale market. Alleghany Power and Rockland Electric joined in 2002. A major expansion of the coordinated footprint went live in 2004 with integration of large utilities such as American Electric Power, Commonwealth Edison, and Dayton Power and Light. Expansion continued apace with seven more utility service areas, with the most recent being Ohio Valley Electric Corporation (OVEC) in 2018. By then, the affected region included thirteen states, and ranged from Illinois in the West to the District of Columba in the East, with over 1000 market entities, 180,086 MW in generating capacity, and 65 million ultimate customers. The energy generation mix was roughly balanced across nuclear, coal and natural gas, with about five percent coming from renewable sources. (PJM Interconnection 2018a)

The centerpiece of power pool operation was economic dispatch of the generating fleet, subject to the security constraints dictated by reliability needs. The security constraints included the industry standard of "N-1" contingency conditions. With an identified list of credible major contingencies, such as the loss of a transmission line or a large power plant, system operation is constrained to ensure that the system will remain stable immediately after any one of these contingency events. The system operator accomplished this feat by maintaining adequate reserves of generation and headroom on transmission, along with various voltage support and frequency response capabilities under the general heading of ancillary services. This is a complicated operational problem, and one of the advantages that facilitated electricity restructuring was the long history and familiar practice in PJM. In principle, all these well-developed operating structures could be maintained, and the major change induced by the expansion of wholesale competition would be in the pricing regime and further efficiencies in coordinated operation.

In the event, PJM launched the first reformed wholesale market in 1997. This followed the long tradition based on engineering cost estimates, a cost-based market. Economic dispatch with cost-based generation produces market-clearing prices analogous to the textbook economics of competitive markets equilibrating supply and demand. These real-time prices would in principle differ by location. The initial PJM model called for a single market clearing price (MCP) across the entire pool. This does not work in theory, and it did not work in practice. (Hogan 2002) In 1998, after a year of operations under this flawed single market clearing price design, PJM converted to a cost-based economic dispatch with locational marginal prices (LMP) that applied to load and generation at each location. In 1999, FERC approved a revised "Market Based" pricing approach where generator engineering cost estimates would be replaced by market bids and offers for most market participants. (FERC 1999) The exceptions to market-based offers would be cases that raised issues of market power, where generators would face offer caps derived from the engineering cost estimates plus a small premium. The new LMP market was accompanied by the introduction of financial transmission rights (FTR) and an early installed reserve capacity market. A PJM Market Monitoring Unit commenced in 1999 to provide market efficiency and market power analysis. In 2000 PJM introduced a day-ahead market and a regulation ancillary services market. Then followed an early version of an initial spinning reserve ancillary service market in 2002, and annual FTR auctions in 2003, for FTR obligations and options. A reform of the capacity market came in 2007 with the Reliability Pricing Model (RPM). An important parallel to the energy markets is the Regional Transmission Expansion Plan (RTEP) coordinating transmission investments and the associated transmission cost allocation.

3. Transition to Open Access and Non-Discrimination

In the last decade of the twentieth century, electricity reform was in the air, especially after the decision to create a wholesale power pool in England and Wales in 1990. The first penetration of competitive supply in the United States came via the Public Utility Regulatory Policies Act of 1978 which mandated purchases from generator types designated as Qualifying Facilities. The ensuing debate in the United States regarding competition in the electric utility sector contributed to the passage of EPAct92 that covered many issues beyond electricity restructuring. However, an important component of EPAct92 established a national policy that would open the wholesale market to competition with many new entrants outside the club of the traditional utilities. The process continued over the next two decades: "competition in wholesale power markets is national policy. The Energy Policy Act of 2005 embraced wholesale competition as national policy for this country. It represented the third major federal law enacted in the last 25 years to embrace wholesale competition."[2]

A key feature of this policy in support of wholesale competition included access to the high voltage transmission system. As FERC recognized, competition for electricity transactions would depend on access to the essential facility of the grid. This principle was not controversial, and the national regulator embraced the broad notions of "open access" and "no undue discrimination." The resulting Order 888 (FERC 1996) set out principles and examined the challenges of giving content to a workable implementation that would meet these objectives.

The long and costly debate surrounding Order 888 revealed a central difficulty that had major implications for competitive electricity market design. The discussion began with the assumption that generators and loads would be able to make bilateral arrangements for contracts of various durations and then arrange for transmission rights, much as had already been done under the open access regime for interstate natural gas pipelines that were also under the jurisdiction of FERC. The term of art was the "contract path" whereby the market participants would identify a path through the grid and make arrangements to utilize the available transmission capacity. However,

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[2] Joseph T. Kelliher, "Statement of Chairman Joseph T. Kelliher," Federal Energy Regulatory Commission, Conference on Competition on Wholesale Power Markets AD07-7-000. February 27, 2007.

unlike natural gas flowing along a specific pipeline, the movement of electric power is completely different.

The essential problem is that power injected at one location and removed at another would travel along every parallel path, distributing itself according to the laws of physics to (roughly) equate the marginal losses on every path. (Hogan 1992) The issue was discussed at length and Order 888 laid out the arguments as explained by the industry. The implications were severe. For example, a fully decentralized market was not possible. There must be a system operator to coordinate use of the grid. Furthermore, implementation of the contract path model was intended to determine how the transmission system would be used, and this required an ex ante determination of the available transmission capacity (ATC) with the assumption of a meaningful relationship between the contract path and physical reality. However, as FERC itself summarized: "A contract path is simply a path that can be designated to form a single continuous electrical path between the parties to an agreement. Because of the laws of physics, it is unlikely that the actual power flow will follow that contract path. … Flow-based pricing or contracting would be designed to account for the actual power flows on a transmission system. It would take into account the "unscheduled flows" that occur under a contract path regime." (FERC 1996) In other words, we need to know how the system is used to identify the ATC. The same contradiction arose in European market design discussions: "in order to compute the maximal use of the network, one needs to make assumptions on the use of the network!". (Boucher and Smeers 2002) The circularity of the argument is inherent in the physics of power systems where the configuration of generation and load fully determines the power flows on the transmission system.

However, asserting a lack of a better approach, FERC adopted the contract-path model as the centerpiece of its initial open access policy: "We will not, at this time, require that flow-based pricing and contracting be used in the electric industry. In reaching this conclusion, we recognize that there may be difficulties in using a traditional contract path approach in a non-discriminatory open access transmission environment, as described by Hogan and others. At the same time, however, contract path pricing and contracting is the longstanding approach used in the electric industry and it is the approach familiar to all participants in the industry. To require now a dramatic overhaul of the traditional approach such as a shift to some form of flow-based pricing and contracting could severely slow, if not derail for some time, the move to open access and more competitive wholesale bulk power markets. In addition, we believe it is premature for the Commission to impose generically a new pricing regime without the benefit of any experience with such pricing. We welcome new and innovative proposals, but we will not impose them in this Rule." (FERC 1996)

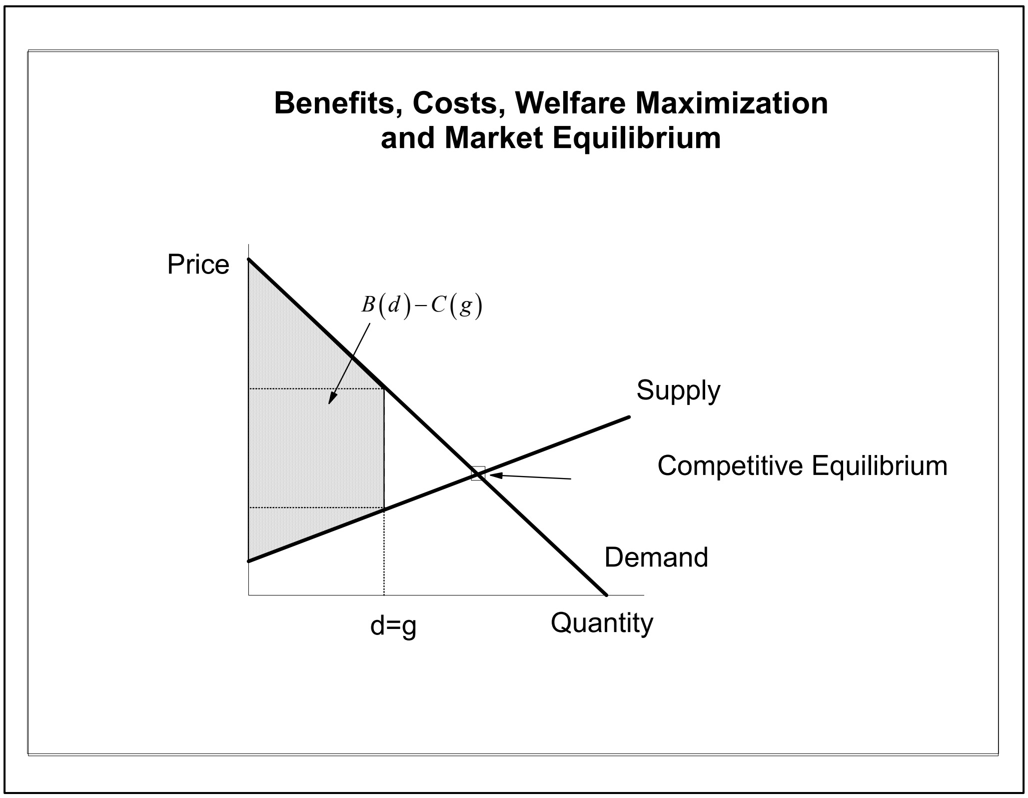
From an economic perspective, the defect of the "contract path" created material market externalities. Individual bilateral transactions would interfere with all other transactions. The contract path model might have been a convenient fiction when there were only a few members of the club of cooperating utilities, but the open access market would be overwhelmed when new entrants responded to the perverse incentives created by the externality. Thus followed the quick imposition of administrative Transmission Loading Relief to undo what the contract-path schedules and the associated market design had done. (Hogan 2002)

Although PJM complied with the pro forma requirements of Order 888, the contract path model was not the focus of its developing market design. Instead, PJM called upon its tradition and experience and pursued an alternative approach based on a power pool and economic dispatch.[3]

4. Electricity Markets and Economic Dispatch

The initial focus was on the real-time wholesale market in PJM. The background and motivating example of competitive market equilibrium came from the textbook example as shown in Figure 1.

Figure 1



The partial equilibrium framework applies for a single good at a single location. The supply curve is upward sloping and the demand curve is downward sloping. Let $B(d)$ define the benefits of

[3] The PJM market design and operating rules include more detail than can be included in this conceptual overview. PJM maintains detailed operating manuals that are continuously revised and available with the revision history on www.pjm.com. Key market deign manuals include M06: Financial Transmission Rights; M11: Energy & Ancillary Services Market Operations; M14B: PJM Region Transmission Planning Process; M18: PJM Capacity Market; M20: PJM Resource Adequacy Analysis.

bid-in load (d) and $C(g)$ the cost of generation (g) offers, which are equal to the areas under the respective curves. The net benefit is $B(d)-C(g)$, as shown in the shaded area of Figure 1. The welfare maximizing goal is to choose a quantity where demand and supply balance and that maximizes the net benefit. Inspection of the graph indicates that this maximum is achieved at the quantity where the supply and demand curves intersect. This is also the point of the competitive equilibrium, and the associated price is the market-clearing price that supports the equilibrium-welfare-maximizing solution. With this market-clearing price, the best (surplus maximizing) choice for the buyer is the quantity at the competitive equilibrium; similarly, the best (profit maximizing) choice for the supplier is at same competitive equilibrium point. The prices support the dispatch.

4.1. Electricity Market Coordination

This competitive equilibrium and welfare maximizing property stands behind the "invisible hand" arguments for the efficiency of decentralized markets that operate without formal coordination. By the same logic, it follows that the visible hand of coordination for competition can achieve the same outcome as the idealized competitive equilibrium. This is important in the electricity system where explicit coordination is required and is always present. Because of the physics, there is always a system operator. The only question at issue is the form of the coordination and the associated pricing.

This observation lies at the heart of the use of economic dispatch for an open access market without undue discrimination. Since PJM already was the system operator, and coordinated the dispatch, the main challenge was to complete the pricing regime.

The basic framework for the electricity market takes the real power load and generation, (d,g), but redefines these as the column vector of values across each location (node or bus) in the network where load, generation and transmission lines connect.[4] The net load is defined as the vector $y=d-g$. Aggregate losses balance the sum of the difference between load and generation, $L(y)+1^t y=0$. Finally, the many transmission and other security constraints defined over the power flows appear in the vector function $K(y)$. With these definitions, we treat the underlying security-constrained economic dispatch problem as:

[4] As is common practice, reactive power flows and voltage magnitudes are treated here as separable following the assumptions of a DC Load model modified to include losses. For simplicity, assume all the functions are differentiable.

$$
(1) \qquad \begin{aligned}
&\underset{d \in D, g \in G, y}{Max} && B(d) - C(g) \\
& && d - g = y, && : p \\
&s.t. && L(y) + 1^t y = 0, && : \lambda \\
& && K(y) \leq 0 && : \mu.
\end{aligned}
$$

For this generic model, everything is assumed to be well behaved enough to yield an optimal solution for the dispatch and associated prices. This is a complicated problem with many variables and constraints. With thousands of locations and thousands of transmission lines, the complete statement of the contingency-constrained problem can run into millions of variables and millions of constraints. Fortunately, system operators are familiar with this model and have workable methods using a blend of optimization tools and operator judgment to approximate an economic dispatch solution.

The formulation in (1) allows for a great deal of flexibility. Fixed supplies and fix loads can enter directly, in addition to explicit benefit and cost functions. A bilateral transaction between generation and load appears as a matched injection at one location and a withdrawal at another.

Following (Schweppe et al. 1988), the dual variables are the locational market clearing prices. In particular, the prices in the vector p obtain as a natural by-product of producing the optimal dispatch in (1). See also (Liu, Tesfatsion, and Chowdhury 2009) .

The prices lend themselves to a natural decomposition:

$$
(2) \qquad p = 1\lambda + \nabla L \lambda + \nabla K^t \mu .
$$

The components have the interpretations as the cost of energy at the system reference bus (λ), plus the marginal cost of losses $(\nabla L \lambda)$ and the cost of congestion $(\nabla K^t \mu)$, both relative to the reference bus. The decomposition is not unique given the dependence on the choice of the reference bus (Rivier and Pérez-Arriaga 1993), but with a given reference bus the decomposition is useful and widely applied.

With optimal dispatch of $y^* = d^* - g^*$, the market settlement with the system operator is:

$$
(3) \qquad p^t y^* = p^t \left(d^* - g^* \right) \geq 0.
$$

This is the market surplus of the payments from load minus the payments to generators that has the interpretation as a loss surplus $\left(\left[\lambda 1^t + \lambda \nabla L^t \right] y^* \right)$, because marginal losses are greater than average losses, plus a congestion surplus $\left(\mu^t \nabla K y^* \right)$ arising from the price differences due to transmission constraints. Aggregate energy payments by load at locational prices will always exceed payments to generators.

The system operator long had this information available, but the prices had not entered into the traditional cost-based economic dispatch with administrative shared savings. In the competitive market, the prices p, known as the locational marginal prices (LMP), becomes a center of attention.

First, just as in Figure 1, the LMP was market-clearing in the sense that it supported the competitive equilibrium at the welfare maximizing solution. In particular, we have:

$$p = \nabla B = \nabla C. \tag{4}$$

Taking the prices as given, each market participant would find the value of its best solution as that produced by the economic dispatch. System operators would soon report that this pricing model makes it much easier to operate the system because of the implied cooperation of the market participants.

Perhaps the most important insight from (Schweppe et al. 1988) deals with the marginal cost of transmission. Transmission of 1 MW from location i to location j is physically equivalent to simultaneously selling 1 MW at i and purchasing 1 MW at j. Hence, by a simple no-arbitrage argument, at equilibrium the marginal cost of transmission must be the same as the value of the purchase minus the sale. Therefore, the marginal cost of transmission must be $p_j - p_i$.

The complexity of the calculation that stands behind this simple rule had defied a workable solution for decades. The "contract path" did not resolve the issue, and the industry had struggled to track all the flows in the system, such as through the failed efforts of the General Agreement on Parallel Paths (GAPP), the "megawatt-mile" morass, and other related efforts. (Ruff 2001) All the complexity is there in the economic dispatch in (1), but the complexity is already internalized by the system operator. Simple application of the resulting LMPs and differences in LMPs cut through the clutter.

This formulation allows treatment of bid-in load with $B(d)$, generation offers with $C(g)$, and point-to-point bilateral schedules of injections and withdrawals to be settled at the difference in the respective LMPs. This is a different approach to market design, with coordination for competition, but it is a feasible market model that does not depend on the unworkable tracking of participant power flows through the grid.

By definition, the efficient outcome is the solution to the economic dispatch in (1). In any system under open access and non-discrimination principles, market participants will have the freedom and discretion to buy and sell power according to their own interests. If market prices support the economic dispatch solution, then the private interests will operate as with the "invisible hand" to follow the efficient outcome. The LMP prices are precisely the market prices that support the economic dispatch. Any other pricing approach would, necessarily, create incentives to deviate from the efficient outcome. It is in this sense that the BBSCEDLMP model is the only electricity market design that can support efficient markets under the principles of transmission open access and non-discrimination.

4.2. Single Market-Clearing Price Settlements

Following the discussion of Order 888, PJM launched its own market reform. The emphasis on flexibility for bilateral transactions was constant, but the reliance on contract-path scheduling was recognized as unworkable and destabilizing. Market participants and the system operator agreed on the necessity of continuing the practice of economic dispatch along the lines of (1). But there was sharp disagreement about the use of the corresponding LMPs as in (2).

The debate centered around the importance of transmission congestion and the apparent complexity of having a different price at each location. In the event, the decision of a majority of the market participants, but not a majority of the utilities, was to adopt a single MCP that would be based on a hypothetical dispatch without transmission constraints. Hence, in the continuing zonal-versus-nodal debate (Hogan 1998), the initial decision by FERC was to accept a PJM market design with a single zone. Since the actual dispatch would have to respect the transmission constraints, the cost of extra out-of-merit dispatch would be paid as an "uplift" cost to be socialized across all loads.

Using engineering costs to define the generation offers, this system was put in effect April 1, 1997. Initially there was no system congestion, and everything worked well because the nodal prices would be about the same as the single MCP, except for marginal losses. But on the first hot day, with high demand in the East and transmission congestion from West to East, the MCP model quickly fell apart. For details, see (Hogan 2002). The essential problem was that the prices did not support the solution, and the option to self-schedule through bilateral transactions provided the avenue to follow the incentives to deviate from the economic dispatch. Parties soon engaged in numerous bilateral agreements to circumvent the single-clearing-price signal. Sellers who were constrained off due to congestion were able to offer their generation bilaterally at a price lower than the single clearing price. The system operator was required to honor these bilateral agreements until system reliability was jeopardized, at which point the market would be suspended. These experiences made clear the flawed assumption underlying uniform non-locational pricing in a constrained network.

4.3. Locational Marginal Price Settlements

PJM's response to the failure of the single MCP model was to turn to implementation of the LMP model for market settlements. PJM had continued with the conceptual and software work for a nodal market during the single clearing price experiment. One year after the start of the single MCP model, PJM made the conversion to LMP. During the year, while PJM ran both systems in parallel prior to full conversion, there appeared a litany of problems with the lingering MCP model, and these required more and more intrusive interventions by the system operator.

Introduction of the LMP model, publishing the so-far implicit marginal costs, and using the prices for the settlement system, produced many surprises. It takes time and analysis to develop an intuitive understanding of the implications of grid interactions and the impact on prices. For instance, it is easy to construct examples where the lowest LMP is lower than the lowest generator offer and, simultaneously, the highest LMP is higher than the highest generator offer. This occurs because the parallel path flows in the network may require increasing generation by x MWs at one location and decreasing generation by $x-1$ MWs at another location in order to meet a marginal increase of system load of 1 MW. It is even possible to construct examples where all the generator offers are positive but some of the LMPs are negative. These conditions, which cannot occur in the single MCP model, are routine in the real transmission system.

The initial implementation of the LMP model in PJM utilized the principles of dispatch-based pricing. The actual dispatch involves both formal modeling such as in (1) and manual operator interventions to handle reliability concerns not otherwise reflected in the dispatch software. Hence the actual dispatch is only approximately optimal. The dispatch-based pricing approach takes the actual metered dispatch as the optimal solution, with a given set of binding constraints, and computes prices that are approximately consistent with that dispatch. For further details, see (Ott 2003).

The switch to market-based generation offers in 1999 provided other advantages (Munoz et al. 2018), but did not change anything fundamental about the market model. PJM has now used the LMP model for two decades, eventually updating the real-time spot prices every five minutes for over 12,000 locations. The price differences caused by congestion are sometimes dramatic, reflecting the reality of the transmission grid. But the experience demonstrates both the feasibility and advantages of linking prices to the actual dispatch conditions.

The BBSCEDLMP dispatch model for the real-time spot market provides flexibility for market participants. For example, generators at a location can enter into long-term energy contracts of a great variety of forms with different profiles and options for delivery. The contracts can be structured as financial contracts-for-differences, a standard form of financial derivative. The actual delivery and receipt will take place in the spot market at the locational price. The contract parties then have a financial obligation between themselves to settle the contracts consistent with whatever provisions they have set. For example, if the contract calls for delivery of 100 MW over the relevant interval, the parties pay to and receive from each other the difference between the spot price at the point of withdrawal and the contract price.

The financial approach of marrying a spot market and contracts for differences has the major advantage that the system operator does not need to know anything about the financial arrangements, over even if a long-term contract exists. The connection to the market is simply handled through the bids, offers, or physical schedules of the parties in the real-time market. Everything else is a separate settlement process that does not affect the dispatch or the spot prices.

This use of long-term contracts for differences would be all that would be required if prices at all locations were the same at the same time, which was part of the motivation for the single MCP. In the LMP model, contracts for differences can be part of the solution at each location. The added requirement to deal with the differences across locations is addressed through Financial Transmission Rights (FTR).

4.4. Financial Transmission Rights

Part of the motivation for the failed "contract path" model was to provide a means of determining the real-time dispatch and use of the transmission grid without requiring a coordinated economic dispatch. But the other part of the story was the need for long-term transmission rights that would allow a generator at one location to arrange a long-term contract with a customer at another location. The strong emphasis on having a long-term contracting capability made this a high priority issue.

The search for physical transmission rights failed because the physics of the electric transmission system made any flow-based definitions of transmission rights unworkable. By contrast, FTRs would provide the critical economic and business requirement for linking contracts for differences at distinct locations.

The real-time transmission charge from location i to location j is $p_j - p_i$. The locational prices are volatile, and this price difference is even more volatile. Hence, parties who wished to enter into contracts for differences, but were at different locations, would be exposed to changes in the spot price of transmission.

Market participants needed a hedge for the locational price difference. And there needed to be some consistent way to account for the capacity of the transmission grid to support power transactions and long-term contracts. The direct solution was to create a financial contract that would be administered by the system operator. (Hogan 1992) The new contract would include a MW amount and a direction of flow between two points on the grid. The contract, an FTR, provides payment of the price difference $p_j - p_i$ for the designated MW amount. If a party scheduled 100 MW between the two points, it would pay the price differential of the price between the point of withdrawal and the point of injection. If the same party also held an FTR for 100 MW between these two locations, it would receive the same payment. Hence, the spot price is perfectly hedged. When coupled with a contract-for-difference at either end, the market participants would be able to have a long-term fixed price for the contract transaction. And when the actual schedules deviated from the contract, the market participants would see the efficient incentives of balancing through the real-time spot market.

The initial implementation of FTRs in PJM only addressed the congestion component of the locational price, ignoring the marginal losses which were not include in the LMPs until later. Under the standard DC Load model that ignores losses, the FTR administered by the system operator have a natural internal correlation. Although it is impossible to define ATC for physical flows in the dynamically changing system, FTRs have an aggregate property that limits the exposure of the system operator. In particular, if the MW injections and withdrawals of the collection of all extant FTRs would be simultaneously feasible given the configuration of the grid in the spot market, then the revenues collected from the spot market locational prices would always be sufficient to make the required payments for the FTRs. (Hogan 1992) With the simultaneous feasibility condition, there would be no revenue exposure for the system operator.

In principle, anyone in or outside of the market could provide the financial equivalent of FTRs on a bilateral basis, but they would not enjoy this same feature of revenue adequacy. Furthermore, absent the provision of the FTRs, the market participants would not be able to obtain the functional equivalent of the benefit of the grid. The multiple owners of a complex grid would not be able to internalize all the congestion costs. Only a monopoly owner, or a monopoly operator, of the grid would provide this service. In the PJM system, with multiple owners of the grid, but a system operator as a monopoly, FTRs provide the missing economic piece to support a long-term contracting market.

Under the FTR model, the exposure of the system operator, grid owners, or market participants is to collective allocation of FTRs that exceeds the capacity of the grid in the spot market. This has been a problem in the past in PJM, confounded by various cost socializations, especially during the period from 2009/2010 to 2013/2014 when FTR funding fell to 67% of the FTR obligation. PJM eventual made a number of corrections and the payout ratio returned to 100% in 2014/2015 through 2018/2019. (Monitoring Analytics 2019)

PJM provides both FTR options and obligations. The obligations require payment of the price difference even when the price differential $p_j - p_i$ is negative. The FTR options do not require payment when the differential is negative. In effect, FTR options are more valuable but they also reduce the transmission capacity for the simultaneous feasibility test.

In addition, PJM uses Auction Revenue Rights (ARR) to distribute the value of the FTRs to the owners of the grid. In essence, the ARR is formally the same as the FTR, but the ARR is allocated through an administrative process to reflect rough justice about the historic investment and utilization in the grid. The logic was to enable parties to replicate their traditional supply paths via ARRs/FTRs as a proxy for their historic entitlements. As load grew, the footprint expanded, and retail access expanded, this proxy has proved to be more problematic. In each annual auction for FTRs, the auction prices set the market value of the ARRs and these funds are distributed proportionally across the ARRs. ARR holders are given the option to "self-schedule" these rights in the annual FTR auction, converting the right to the auction revenues into the actual FTR.

Investment in expansion of the grid creates incremental transmission capacity and therefore incremental FTRs. If the combination of the incremental FTRs and the existing long-term FTRs meet the simultaneous feasibility test, then the award of these incremental rights and the associated congestion collections preserves FTR revenue adequacy going forward, indefinitely.

PJM pioneered the use of FTR auctions. The details, with long-term auctions and short-term updates are more complicated, along with various rules about allocating other system uplift costs. In addition, there is a continuing controversy about the deviations of the actual payments under FTRs and the implied value as revealed in the forward auctions. (Monitoring Analytics 2019)

FTRs are forward contracts, and holders of FTRs must comply with various credit requirements. Designing good credit risk protocols is a standard business issue that extends beyond the main focus of electricity market design. In 2018, PJM faced a significant problem of default on the large FTR position held by GreenHat, LLC. For further details, see (Monitoring Analytics 2019).

4.5. Day-Ahead Market

Soon after the second launch of the real-time market in April 1999, market participants began a discussion about development of a day-ahead market. The real-time market took the availability of (most) of the generation as given, and solved for the energy dispatch in (1). There were a few related actions to ensure enough capacity was started and on-line, but this was a relatively minor part of operations as initially the majority of supply was self-scheduled.

When looking ahead over a longer period like a day, however, there would be many more decisions required about commitment of generating units that had longer lead-times. The change in horizon and the ability to commit units results in the economic dispatch problem expanding into an economic unit commitment and dispatch problem. This would open the door to more formal consideration of multi-part generation offers to include start-up costs, minimum run times, and related complications that arise in the management of real systems.

For market participants, a day is a long time in electricity systems, and real-time prices can be quite volatile. There was a popular demand for a mechanism that operated one day-ahead to create hedges for the real-time operations to help manage this volatility. Although these hedges could be arranged in the open market, the system operator again had a special role to play in coordinating day-ahead schedules and dispatch to respect the capabilities of the transmission system. For the same reason as found for FTRs, only the system operator can determine a consistent set of day-ahead contracts that could be converted to physical delivery within the limits of reliability.

The essence of the problem was to create a new model that included unit commitment and related control variables $u \in U$, and expanded the optimization to include these control variables.

$$
(5) \qquad \begin{array}{ll}
\underset{d\in D, g\in G, u\in U, y}{Max} & B(d) - C(g,u) \\
 & d - g = y, \qquad :p \\
s.t. & L(y) + 1^t y = 0, \quad :\lambda \\
 & K(y) \le 0 \qquad :\mu.
\end{array}
$$

Typically formulated as a dynamic model with an hourly interval, load bids and generator offers are for day-ahead forward contracts that will be settled against the relevant intervals for the real-time dispatch in (1). Multi-part offers with start-up, no-load and multiple steps with incremental energy offers that make up a generator cost are incorporated in (5), and the resulting schedules provide the hedges for real-time markets. To the extent one's real time generation or load matches the day-ahead schedules, the party is fully insulated from real time price volatility.

The day-ahead model includes a Reliability Unit Commitment (RUC) for supplemental units if needed to ensure real-time reliability. In effect, this can be included as part of the constraints in (5). (Cadwalader et al. 1998)

One problem with the day-ahead unit commitment model is that the unit commitment variables are integers, and thus the model in (5) may not have prices that fully support the solution. The broader topic is discussed under the name of Extended LMP (ELMP). Essentially, the initial PJM implementation accepted the optimal day-ahead unit commitment as given, which reduces (5) to a dynamic version of (1), and took the results as the day-ahead prices. This gives rise to cases where generators could be committed but losing money at the day-ahead prices. In essence, PJM's practice is to pay an added uplift to cover the difference and ensure support of the commitment and dispatch. The extra uplift costs are spread across the loads.

The day-ahead market includes explicit and implicit transmission schedules. Since it was not intended to sell transmission capacity twice, introduction of the day-ahead market required a change to redefine the settlement for FTRs as at the day-ahead prices. In effect, the day-ahead market purchases all the outstanding FTRs and reconfigures the rights to match the transmission dispatch in the day-ahead, which will then be settled at the real-time prices. A market participant that wishes to carry through an FTR to the real-time market can achieve this end by submitting a matching point-to-point schedule in the day-ahead market.

Very few of the decisions in the day-ahead energy dispatch and commitment have an immediate physical effect. Commitment decisions are the principal example, but the related energy dispatch schedules are the functional equivalent of financial forward contracts. This recognition stimulated the rise of so-called "virtual" transactions where the bids and offers in the day ahead market are not directly connected to any load or generation, and the market participant simply unwinds the contract through the real-time settlements. Hence, a virtual award for 100 MWh of generation in the day-ahead will lead to a payment at the day-ahead price and a corresponding obligation at the real-time price. In other words, the virtual bidder is arbitraging the difference between the day-ahead bid and the expected real-time price.

To a material extent, virtual bidding is impossible to avoid as long as generators and loads have any discretion for offers and bids in the day-ahead market. In PJM, capacity resources have a must-offer obligation in the day ahead market, but flexibility in offers when not constrained on. Load has much more flexibility with respect to the amount it can purchase in the day ahead market. Further, the entry of additional financial market participants without explicit physical assets substantially expands the number of possible participants in the day-ahead market. The resulting increase in liquidity from financial participants is important for removing conditions that would otherwise allow an exercise of market power by either generation or load. The limited empirical estimates support the view that allowed explicit virtual bidding provides material benefits and enhances convergence between day-ahead and expected real-time prices. (Hogan 2016) For PJM, difference between “the average real-time price and the average day-ahead price was -$0.06 per MWh in 2017, and $0.06 per MWh in 2018.” (Monitoring Analytics 2019)

4.6. Capacity Markets and Resource Adequacy

From the beginning of the PJM restructuring process, regulators were concerned about the ability of markets to support resource adequacy. The objective was to ensure that installed generation capacity was maintained with a reserve margin large enough to limit events leading to involuntary load curtailment with a probability of an event occurring no more than the one-day-in-ten-years standard. PJM’s various state regulators were not convinced that the energy market alone would provide revenue sufficient to support investment in new generation to meet this standard. The call was for a capacity market that would provide forward looking support for generation asset investment to meet the resource adequacy standard.

Designing forward capacity markets is much harder than designing real-time or even day-ahead energy markets. The difficulties are fundamental. Forward capacity purchased for availability many years ahead is not an observable quantity. There must be some connection, eventually, to measurable quantities such as energy delivered. While these assumptions were made in planning models, translating this into market design consistently has been challenging. Defining this connection without simply creating a forward energy market is difficult and contentious. The original definition of capacity reflected the traditional dispatchable thermal generation plants. But capacity markets soon had to take on definitions of the contribution to capacity of intermittent resources, energy demand response, and later short-term storage devices.

Perhaps most complicated is the task of dealing with transmission constraints years in the future. If we knew how to do this well, the contract path model might have worked. But identifying the ability of capacity resources to be delivered to meet load requirements under stressed conditions is not a simple modeling task. The practice in PJM is to make some engineering judgements and construct a zonal model for capacity with a simplified transportation model that does not explicitly account for the actual power flows and transmission constraints.

There are two classes of generators in PJM. Energy-only resources are connected to provide energy in the real-time market and have only minimal interconnection requirements, e.g. they must be able to operate without causing operating problems, but their interconnection upgrades are not designed to assure the resource is deliverable to the system on an integrated basis. Capacity Resources have more stringent interconnection requirements and are connected to the grid and allowed to participate in the capacity market only after meeting an engineering deliverability test. To be certified as “deliverable”, a new resource may be required to make investments in upgrading the grid. In exchange for such upgrades they receive a Capacity Interconnection Right. But once certified, such capacity resources only retain their CIRs and ability to participate in the capacity market if they continue to offer into the capacity market. They lose their CIRs after 3 years if they do not participate (versus clear) in the capacity market auctions.

A major revision of the PJM capacity market, referred to as the Reliability Pricing Model (RPM), was implemented effective June 1, 2007. There are Local Deliverability Areas (LDAs) for capacity. For each LDA, PJM produces a forward estimate of the peak energy demand, the capability to accept transfers from the rest of the footprint, and a target level of reserves needed within the LDA. The interface capacity for the zones is set according to a one-day-in-twenty-five-year standard for transmission flow capacity. This conservative planning requirement is used to approximate the infinite internal transmission that PJM assumed when determining the one-day-in-ten-year requirement for generation reserves for PJM as a whole.

Given the target level of internal requirements for each LDA, PJM utilizes a Cost of New Entry (CONE) for a typical combustion turbine and the Net CONE (CONE adjusted for energy and ancillary services income) to establish a demand curve for each represented LDA. The CONE represents the levelized capacity cost that would have to be earned on average to support investment in the turbine. This estimate is reduced to the Net CONE by subtract an estimate of the energy and ancillary services (E&AS) revenues that will be earned, based on a backward-looking average on-peak dispatch of the turbine plant. A significantly positive Net CONE is an indicator of the "missing money" in the energy market. (Joskow 2008) In PJM, revenue adequacy from the E&AS market alone has not been sufficient to support investment. (Monitoring Analytics 2019) The RPM capacity revenues have been a significant and growing part of the PJM market. Capacity revenues represent almost 100% of the income for demand response capability that is sold as capacity.

Net CONE and an installed reserve requirement set an anchor point for the Variable Revenue Requirements (VRR) curve, an administratively set demand curve. The VRR is a piecewise linear function similar in appearance to a demand curve, although there is no connection to demand other than to meet the Resource Adequacy requirement. The original intent of the shape of the VRR was to create a control type mechanism which would result in prices over time oscillating around the Net CONE with a frequency/cycle satisfactory to meeting the one-day-in-ten-year reliability requirement. This objective has been less visible over the twelve years of regulatory adjustments to the capacity construct.

With this VRR and zonal model, the RPM three-year-ahead forward auction and interim adjustment auctions combine offers from approved resources to determine capacity resource awards and capacity prices. A forward auction must-offer obligation (with limited exception) applies to all resources with CIRs. The winning capacity resources have an obligation to offer into the subsequent day-ahead and real time energy markets.

The Polar Vortex cold snap in the winter of 2014 revealed a problem in non-performance of generating capacity. At the peak PJM reported that 22% of total generating capacity was unavailable. (PJM Interconnection 2018b). This was problematic as the underlying reliability models used by PJM assumed that forced outages of generators were random and independent. Clearly this wasn't the case as cold weather froze operating equipment, stopped fuel conveys and made gas supplies unobtainable in certain areas. This precipitated a process to strengthen the capacity performance incentives and non-performance penalties. A modified paradigm referred to as Capacity Performance was put in place with stiffer penalties for unavailability during specified periods. The full effect of the new model would not be in place until the Delivery Year 2020/2021, illustrating the lag time for contentious market reforms and the fundamental forward nature of the capacity market design. Under the Capacity Performance requirement reform, capacity resources that are called upon but do not deliver energy will be charged at the hourly rate of 150% of the annualized Net CONE allocated over the estimated 30 hours when the resources would be needed. PJM calculates this value for the RTO resources as just over $3,300/MWh for 2020/2021, with a cumulative stop/loss of 150% of Net CONE. This compares with the 2018 annual load weighted average LMP of $38/MWh. With the exception of the exemptions for solar and wind, this capacity performance penalty structure provides a significant incentive to meet the capacity obligation.

A feature of the Capacity Performance penalty has the revenue collected from the under-performing assets shared among the over-performing assets, including those that are not capacity resources. Therefore, the marginal incentive for generators is similar to real-time scarcity pricing. However, the prices are not translated into the market prices as seen by the loads. This will create situations where the same product, energy at a location, has more than one implied spot price. Deficient generators will see the price as LMP+$3,300/MWh, and they could take actions incurring large costs to capture the market price and avoid the $3,300/MWh penalty. But loads at the same location would be paying only the market LMP. Given experience, it would not be surprising if the inconsistent incentives create unintended consequences for market efficiency.

4.7. Transmission Expansion and Cost Allocation

The Regional Transmission Expansion Plan (RTEP) sets out investments in the transmission grid to meet several different "drivers": i) reliability, ii) market efficiency, and iii) public policy objectives. In this context reliability refers to various operating standards to meet dispatch security constraints and reliability standards. Market efficiency refers to improved economic performance through reduced congestion in the forecast economic dispatch. Public policy projects are those that do not arise under the first two categories but are needed to meet public policy objectives, such as interconnection of distant renewables resources. Transmission investments typically affect all three of these benefits, and thus the RTEP also includes procedures for evaluating multi-driver projects.

In the background of all this planning there are also Supplemental Projects that can be built by the various transmission owners outside of the RTEP, with the requirement being that the Supplement Project not diminish the system capability. In recent years, Supplemental Project spending has far exceeded RTEP central transmission planning investments.

Although there are provisions for merchant investments, where the costs and transmission benefits (e.g. incremental FTRs) are assigned to the merchant provider, the main outlines of the RTEP are essentially the same as found in traditional monopoly utility planning practices. PJM organizes stakeholders in two related processes for five-year and fifteen-year planning horizons. Using forecast of load, costs, and related infrastructure changes, PJM conducts production simulation analysis across a range of scenarios.

The choice among reliability projects broadly follows the standard of the least-cost means to meet the constraint. Market efficiency projects are evaluated according to changes in the simulated production cost and subject to a benefit-cost ratio of 1.25 as a minimum threshold. Public policy projects would be proposed by other government entities requesting the transmission investment. PJM has introduced limited competition and open seasons for various RTEP transmission projects. This new element, linked to FERC Order 1000 mandates, has proven contentious with the introduction of competition in an area previously the exclusive domain of regulated monopolist transmission owners. (FERC 2011)

Cost allocation for the initial existing transmission assets follows a "license plate" method which, in effect, recovers historical costs as a zonal connection charge, with different charges in each zone. Cost allocation for transmission expansion investment follows a series of rules that are a mixture of proportional allocation based on load ratio shares and a distribution factor (DFAX) based on a hypothetical power flow analysis. Notably, these load-ratio and DFAX methodologies are not derived from the cost-benefit analysis performed with the production simulations. (Hogan 2018) The result can be a sharp divergence between the cost allocation and the anticipated benefits. PJM members have continually disputed the resulting allocations, particularly those in recent years where the allocation criterion has been changed from violation based DFAX to beneficiary based DFAX. The allocation disputes have also spilled over into the merchant transmission arena where owners of controllable DC lines between PJM and NYISO have engaged in litigation regarding criteria for the application of costs responsibility and eligibility for certain services as they modify the basic service taken to avoid certain cost allocations.

4.8. Market Power Mitigation

Mitigating a possible exercise of market power has been a continuing thread of electricity market restructuring. An early focus was on generator market power. The concern derived from theoretical arguments and experience in other markets, such as the power pool in England and Wales, that concentrated ownership of generators would create incentives to withhold some supply in order to raise market prices and increase profits on the remaining generation. (Wolfram 1999)

The central tool to mitigate generator market power in PJM is through the must-offer requirement for capacity resources with various associated offer caps. In a simplest case with an increasing incremental energy offer, an offer cap sets an upper limit on the generator's offer price. For generators deemed to have market power, either in general or under constrained transmission conditions, the cap is set based on an agreed upon measure of a 10% premium over an audited cost on file with PJM. The capped offer remains as part of the dispatch in (1) which produces the associated market-clearing LMP. The generator is paid according to the LMP at its location. Since the perfect competitive incentive, without market power, would be to offer at true marginal cost, the outcome of mitigation will be a close approximation of what would occur in a competitive market if the cost estimate used for mitigation is reasonably accurate.

In the presence of virtual bidding, easy market entry makes the day-ahead market highly competitive and it would be difficult to exercise market power on a sustained basis. In any event, a primary function of the market monitor is to track market performance and identify any evidence of market manipulation. The reports of the market monitor consistently find results of the energy market as competitive. For the various ancillary services, such as regulation and reserves, the market monitor finds the structure as not competitive, indicating a potential problem, but finds the actual market behavior as competitive.

The capacity market is the principal exception to this broadly competitive finding. Here the market monitor finds both the structure and performance as consistently non-competitive. (Monitoring Analytics 2019) The problems affect supply offers that are deemed too high as being non-competitive, as well as the associated challenges of accommodating subsidized generation where the supply offers are too low.

5. Price Formation and Market Design Challenges

The substantial progress of the PJM market after more than two decades of operation as an open access, non-discriminatory power pool must be counted a successful market design (SMD). (Cramton 2017) The main features of BBSCEDLMP should be the starting point for any future standard market design. The remaining challenges are not as significant those of the first days of the market opening in 1997. However, PJM will likely maintain its process to prioritize and improve on a number of electricity market design challenges.

5.1. Scarcity Pricing and Operating Reserve Demand Curves

Scarcity pricing refers to conditions when load is close to using all available generating capacity, including capacity reserved to meet contingency constraints. In textbook theory, prices should rise to reduce demand and ration the available supply. In addition to supporting reliability, scarcity prices would provide a major element in supporting returns on generation investment. For a variety of reasons, electricity market implementations have embedded rules and procedures that tend to suppress market prices, particularly under scarcity conditions. (Joskow 2008)

PJM implemented a limited form of scarcity pricing in 2012 through penalty factors that would apply to operating reserve shortages during scarcity conditions. However, the penalty factors were set more based on cost principles than on the value of the reserves. The impact on scarcity pricing was insufficient, and PJM found that the relative share of energy prices in the total contribution to generator revenues was declining significantly.

An Operating Reserve Demand Curve (ORDC), based on valuing the impacts of outages and reserve shortages, provides a practical way to address scarcity pricing within the framework of current economic dispatch models. (Hogan 2013) To address its scarcity pricing problem, PJM proposed a major reform that would significantly revise the prior penalty factors and implement a version of an ORDC. Under this proposal, the scarcity price within a constrained zone could rise as high as $12,000/MWh. (PJM Interconnection 2019)

The proposed PJM ORDC reform targets in part the expected need for and greater use of flexible operating reserves. PJM does not have the same potential for renewable resources as found in other regions. But policies to support renewable generation are likely to produce a similar trend of an increasing penetration of intermittent resources.

5.2. Market Design and the Green Agenda

Although PJM has been behind other regions in the arrival of renewable energy resources, the future could be quite different. The challenges include dealing with the intermittent supplies that can increase stress on the system. The balanced mix of generation resources in PJM provided a substantial capability that helped accommodate the needs of efficient and reliable economic dispatch. Future increases in intermittent resources will require emphasis on flexible resources, better look-ahead dispatch practices, and related operating procedures that should develop as part of the natural evolution of the RTO.

A closely related issue will address modifications in the basic market design needed to accommodate a different cost structure, the implications for market-clearing prices, and the associated long-term incentives. In particular, the arrival of increasing volumes of zero marginal-cost renewable resources prompts a concern that this will drive down energy prices and make the fundamental market design unravel. (Lopes and Coelho 2018) (Joskow 2019)

A notable feature of the formulation in (1) is the lack of any specification of the details of the underlying cost functions. The model is quite general, and the basic analysis from first principles is unaffected by the arrival of low or zero-variable cost resources. The prices, values and incentives all change, but the basic efficiency arguments all lead to the same market design and pricing prescriptions. The principal conclusion of a closer analysis is that the importance of scarcity pricing increases with the increasing penetration of zero-variable cost resources. In a hypothetical limiting case of only such resources with an energy-only market, scarcity prices would supply all the revenues in the energy market and all the incentives for investment. Hence, the direction of the future for PJM is to emphasize the scarcity pricing reforms it has already proposed. (PJM Interconnection 2019) (Hogan 2019)

5.3. Disconnect Between Economic and Reliability Standards

Resource adequacy and reliability standards in PJM and elsewhere typically invoke the one-day-in-ten-years standard for system failures that lead to involuntary load curtailments. This standard takes slightly different forms, but all the implementations have the characteristic that the standard continues because it has always been the standard.

The logic behind the rule has been challenged repeatedly by showing that the implied value of lost load is orders of magnitude above the levels that actual loads would be willing to pay. (Telson 1973) (Wilson 2010) The analysis of the economic level of installed capacity compared to the historical reliability standard has been quite detailed in work for the Texas system operator. (Newell et al. 2018) The implied economically efficient reserve margin for installed capacity is materially lower than that required by the traditional reliability standard.

The gap between these installed reserve requirement estimates implies that energy-only markets with efficient scarcity pricing require either revising the reliability standard or providing some other means to support pricing and investment. A capacity market, as in PJM, is one approach. An ORDC constructed with conservative assumptions, as ordered by the Public Utility Commission of Texas, is another.

5.4. Beneficiary Pays and Transmission Cost Allocation

In its landmark Order 1000 on transmission expansion and cost allocation, FERC set out the fundamental requirement for transmission expansion criteria and the "beneficiary pays" principle for cost allocation. (FERC 2011) The cost-allocation principle is important for maintaining compatibility among the investment incentives for load, generation and transmission. The broad principle, reinforced by a series of Federal court decisions, required that cost allocation rules be "roughly commensurate" with the investment benefits.

Almost immediately, implementation of the rule revealed either an unwillingness or an inability to follow the logical precepts of the beneficiary-pays principle. (Radford 2013) PJM is not alone in facing a challenge to make the transmission expansion process, cost-benefit analyses, and cost-allocation rules conform to the basic principles.

5.5. Buyer Market Power and Minimum Offer Price Rules

The RPM capacity auctions are vulnerable to manipulation by the functional equivalent of market power exercised by loads. Although individual loads are generally not large enough to influence capacity market prices, state governments can act on behalf of loads to manipulate capacity prices. The process first appeared with New Jersey proposing subsidies for a new natural gas plant that customers would be required to subsidize but where a major objective was to lower capacity market prices to the greater benefit of those same customers.

The same effect happens through any subsidies for competing generation, such as through policies to support renewables or maintain existing fleets of generating plants in the name of improved resiliency. The impact of subsidies in the energy market is ubiquitous and material. (Nordhaus 2013) "Subsidies are contagious. Competition in the markets could be replaced by competition to receive subsidies." (Monitoring Analytics 2017) The main response in PJM has been through RPM Minimum Offer Price Rules (MOPR) intended to remove the effects of various subsidies and determine a forward capacity price that is not subject to manipulation. This continuing discussion promoted then FERC Chairman Norman Bay to argue that regulators of electricity markets cannot solve this problem. (FERC 2017)

5.6. Multi-period Dispatch and Price Consistency

In the real-time spot market, PJM utilizes a look-ahead for various commitment and dispatch decisions. The dispatch updates every five-minutes, with a rolling look-ahead period set by system conditions and varies from 15 minutes for generators to up to 2 hours ahead for various ancillary services. The real-time LMP pricing model applies for each five-minute dispatch interval without a look-ahead feature.

Dispatch intervals are not separable. For example, ramping limits can constrain the dispatch and affect both cost of operations and intertemporal prices to reflect these limits. In principle, the formulation in (1) can include intertemporal constraints and the associated prices. The LMP prices estimated separately for each period may not be the same and might not support the solution with binding ramping constraints. Calculating the prices for each interval with a look-ahead with related constraints, and then updating prices after every five-minute interval, is feasible, would provide consistent intertemporal prices when the forecast and actual load and operating conditions are the same, and is the practice in other organized markets. In the system with constantly changing forecasts, the deterministic models cannot ensure that the forecast prices and actual prices would be the same. Hence, there is another application of uplift payments to support the dispatch. However, simulations for the ISONE system found test cases where the deviations produced for the rolling calculations were relatively small. (Hua et al. 2019)

5.7. Day-ahead and Real-time Market Design Interaction

The PJM real-time and day-ahead market models in (1) and (5) are deterministic. The models are based on bids and offers and expected system conditions. The real dispatch faces uncertain conditions over the near future in real-time, and over the day in the day-ahead problem. Full formulation of a stochastic optimization and the accompanying market equilibrium is a research topic but not yet a workable possibility for large-scale power systems with security-constrained dispatch. (Bjørndal et al. 2018) However, the treatment of operating reserves in real-time and day-ahead in PJM is an example of building in approximations that serve to proxy for some of the major effects of uncertainty while maintaining a simplified representation in a deterministic model. The problem becomes even more interesting in the presence of virtual bidding and assumptions of perfect arbitrage between day-ahead and expected real-time prices. (Hogan and Pope 2019)

5.8. Extended Locational Marginal Pricing and Energy Uplift

The market model with unit commitment, as in (5), includes binary on-off decisions for generators and other facilities that violate the conditions that guarantee that the LMPs support the efficient solution. In this more general model, there may be no set of market prices that supports the efficient solution. Recognized early in the development of electricity markets, the general practice is to pay generators an additional "uplift" whenever the energy revenues at the market prices are not sufficient to support the efficient outcome.

Under these conditions, different choices for the locational prices lead to different uplift amounts. Setting the prices to minimize the total uplift payments is possible in principle. (Gribik, Hogan, and Pope 2007) However, the theoretical ideal can be computationally intractable for a real system such as PJM.

The alternative approach, sometimes described as Extended Locational Pricing (ELMP), would choose the market prices according to a separate pricing model that approximates (5) by relaxing the integer restrictions to treat commitment decisions as continuous rather than binary. Although the associated dispatch in the pricing model need not be the same as the actual dispatch, the resulting prices are a good workable approximation to the exact minimization of uplift. (PJM Interconnection 2017) This would be a generalization of the similar treatment of "fast start" resources already approved by FERC. (FERC 2019)

6. Conclusion

The physics of power transmission systems make existing electricity markets unlike markets for other commodities. Markets cannot solve the problem of electricity market design, and simple analogies to other markets can lead design astray. PJM has been at the forefront of applying first principles of engineering and economics in the context of providing coordination for competition as needed to support efficient markets. Perfection is elusive, both in theory and in practice. PJM strives for the best approximation of Successful Market Design organized around bid-based-security-constrained-economic-dispatch-with-locational-marginal-prices. The evolution of market design, to accommodate the changing mix of load and generation resources, should avoid mistakes of the past and continue to emphasize the fundamentals while improving the characterization of scarcity pricing, dynamic dispatch and the close connection between physical and financial markets.

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