An Overview of PJM Energy Market Design and Development

Zhenyu Fan, Tim Horger, Jeff Bastian and Andrew Ott

Abstract—**The seven Independent System Operators and Regional Transmission Organizations (ISO/RTOs) in the United States coordinate reliable power grid operations for two-thirds of its population and two-thirds of its electric generation. As one of the largest ISO/RTOs, PJM provides regional planning and operation, energy market operation, outage coordination, transactions settlement, billing and collections, risk management, ancillary services, credit risk management, and more services which have broadened significantly in recent years. This paper shows how PJM plays essential roles in managing and improving flow of energy, money and information in energy markets. Market development in recent years in PJM is presented. PJM also implements the planning function through the Regional Transmission Expansion Planning (RTEP) process. This paper also discusses how Financial Transmission Rights (FTRs) are acquired and how the value of FTRs is determined as risk management service in PJM.**

***Index Terms*—Energy Market, Day-ahead Market, Real-time Market, Ancillary Service, Financial Transmission Rights, Economic Transmission Planning.**

I. INTRODUCTION

VERTICALLY integrated electric utilities monopolized the way they controlled, sold and delivered electricity to customers. A competition is guaranteed by establishing a restructured environment in which customers could choose to buy from different suppliers and change suppliers as they wish in order to pay market-based rates. In this regard, the Federal Energy Regulatory Commission (FERC) issued the 888 in 1996 requiring all public utilities that own, control and operate facilities to file open access non-discriminatory tariffs. This rule caused public utilities to functionally unbundle wholesale generation and transmission service. In addition, FERC issued 889 for the development of an Open Access Same-time Information System (OASIS). FERC Order 2000 issued in December 1999 established the concept of the regional transmission operator (RTO) and requires transmission operators to make provisions to form and participate in these organizations [1]. These rules gave birth to new classes of entities such as an Independent System Operator (ISO) / Regional Transmission Organization (RTO). These ISO/RTOs are located across United States and Cananda as shown in Figure 1. As one of them, PJM is a regional transmission organization with the primary task of ensuring the safety, reliability, and security of its bulk electric power system [2].

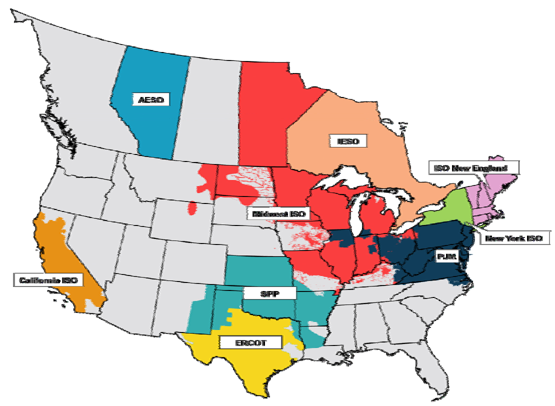

Figure 1 ISOs and RTOs in US and Canada

This paper addresses several issues related to PJM market development and economic transmission planning. The purpose of this paper is to highlight some of the principles in PJM market operations. Section 2 illustrates the history of PJM market and its development. The two settlement energy market, ancillary services and reliability pricing market is covered in section 3. Section 4 describes the current status of the Financial Transmission Rights (FTR) market in PJM. Economic transmission planning is presented in Section 5. Based on the analysis and discussion, the conclusions are drawn in Section 5.

II. PJM HISTORY

PJM had its beginnings in 1927 when Philadelphia Electric Company, Pennsylvania Power & Light, and Public Service Gas & Electric Company of New Jersey joined their 230 kV transmission system to operate as a single entity. Through the years, another six utilities in the Mid-Atlantic region joined to form a regional power pool. By the time deregulation unfolded in the 1990s, PJM had established a reputation of excellence in the area of large scale power operations. PJM operated its eight member utilities as a single entity for the scheduling of generating units in order to improve economies of scale and generate savings that were passed on to those utilities.

The PJM market began operating under the Two Settlement System on June 1, 2000. The success of the PJM market has spurred its expansion. On May 1, 2004, the Commonwealth Edison Company of Chicago, IL joined PJM. On October 1,

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2004, Dayton Power & Light of Dayton, OH and the American Electric Power Company of Columbus, OH also joined PJM Followed by the Duquesne Power & Light Company of Pittsburg, PA on January 1, 2005, and Dominion-Virginia Power Company on May 1, 2005. The footprint of PJM encompasses 13 states and the District of Columbia and includes 56,250 miles of transmission lines, 164,634 Megawatts of generating capacity and 164,260 square miles of service territory, serving a population of 51 million people. The major events in PJM market development are demonstrated as a time line in Figure 2.

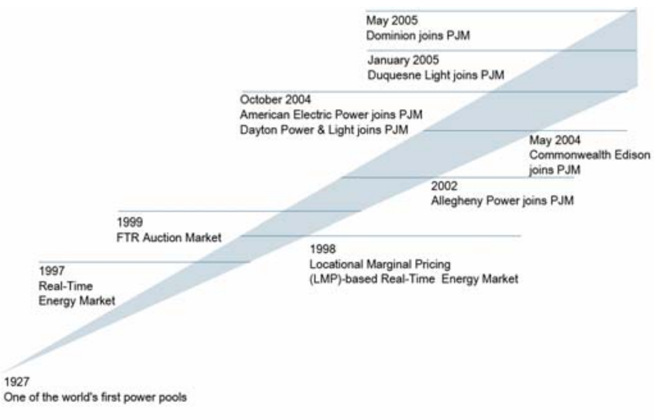

Figure 2. Milestone of PJM Market Development

III. PJM MARKET DESIGN AND DEVELOPMENT

In developing new markets for wholesale electricity services, PJM employed collaborative process to establish systems and rules that ensure that the markets operate fairly and efficiently in recent years as shown in Figure 3. Deregulation marked the rise of marketers, independent power producers, regional transmission organizations and independent system operators. PJM was faced with the challenge to create a market for energy that accommodated all these various players. This was accomplished fundamentally using two settlement system [3].

PJM's Energy Market operates much like a stock exchange, with market participants establishing a price for electricity by matching supply and demand. The market uses locational marginal pricing that reflects the value of the energy at the specific location and time it is delivered. If the lowest-priced electricity can reach all locations, prices are the same across the entire grid. When there is transmission congestion, energy cannot flow freely to certain locations. In that case, more-expensive electricity is ordered to meet that demand. As a result, the locational marginal price (LMP) is higher in those locations.

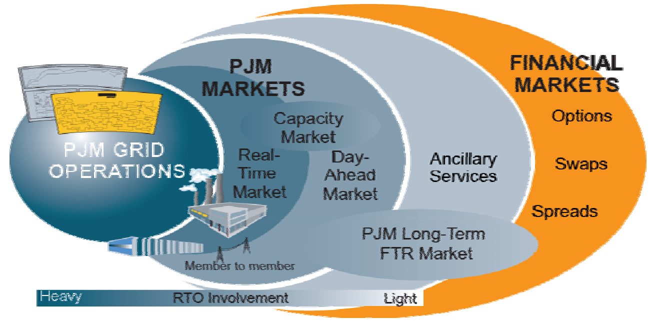

Figure 3 PJM Market Structure

A. *Day-ahead Energy Market*

PJM day-ahead market is a forward market in which hourly clearing prices are calculated for each hour of the next Operating Day based on generation offers, demand bids, and bilateral transaction schedules submitted into the day-ahead market. The day-ahead schedule is developed using least cost security constrained unit commitment and security-constrained economic dispatch programs. The objective is to minimize total production cost subject to certain constraints.

In PJM, the day-ahead commitment and dispatch is currently implemented through a configuration of unit commitment provided by RSC, security constrained economic dispatch provided by SPD, and contingency analysis provided by SFT. The process follows the following nominal sequence, as shown in Figure 4:

Export: Market Data Base (MDB) export of CSV data

TOPPER: Conversion of network model

RSC: Unit commitment and de-commitment

SPD: Economic dispatch and optimal power flow

SFT: Contingency analysis

SPD: Re-dispatch with additional security constraints (as needed by user and/or SFT)

Import: Load results into MDB

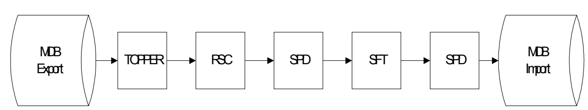

Figure 4 PJM Day-ahead Sequence

SPD and SFT sequentially solve each study interval. Operator control of this process is managed through the MOI (Market Operator Interface).

Day-ahead settlement is based on day-ahead hourly LMPs. For each hour of the day-ahead market, each scheduled demand pays its day-ahead LMP for the hour; each scheduled generator is paid its day-ahead LMP for the hour. FTR holders receive congestion credits based on hourly day-ahead LMP values.

B. *Real Time Energy Market*

Another PJM function is to match the instantaneous load with the instantaneous generation throughout RTO footprint. PJM operates a real -time balancing market that is open to participants. The generation of imbalance service providers can be adjusted on a second-by-second basis by PJM dispatches. The real-time market is the real-time energy market during which hourly clearing prices are determined by the actual system operations security-constrained economic dispatch in which current LMPs are calculated at five-minute intervals based on actual grid operating conditions as described by the PJM state estimator and are published on the PJM Web site. PJM settles transactions hourly and issues invoices to market participants monthly.

LSEs pay real-time LMP for any demand that exceeds their day-ahead scheduled quantities (and receive revenue for demand deviations below their scheduled quantities). Generators receive prices for any generation that exceeds their day-ahead scheduled quantities (and pay for generation deviations below their scheduled quantities). Transmission customers pay congestion charges for bilateral transaction quantity deviations from day-ahead schedules. All spot purchases and sales in the real-time market are settled at the real-time prices.

Figure 5 shows the relationship of average day-ahead and real-time LMP. The convergence is driven by the fundamental incentives of the two-settlement based energy market.

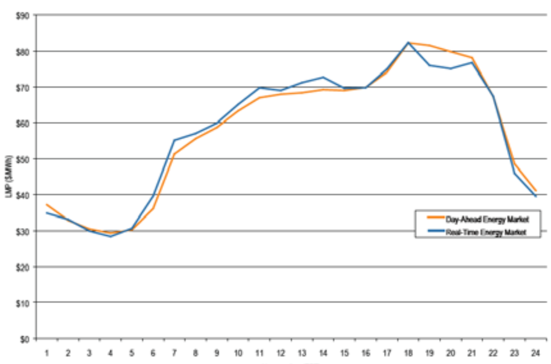

Figure 5 PJM Hourly system average LMP: 2005

C. Ancillary Services

Ancillary services support the reliable operation of the transmission system as it moves electricity from generating sources to retail customers.

PJM currently operates two markets for ancillary services – regulation and synchronized reserve.

Regulation service corrects for short-term changes in electricity use that might affect the stability of the power system. It helps match generation and load and adjusts generation output to maintain the desired frequency. Load-serving entities (LSEs) can meet their obligation to provide regulation to the grid by using their own generation, by purchasing the required regulation under contract with another party or by buying it on the regulation market.

Synchronized reserve service supplies electricity if the grid has an unexpected need for more power on short notice. The power output of generating units supplying synchronized reserve can be increased quickly to supply the needed energy to balance supply and demand. LSEs can meet their obligation to provide synchronized reserve to the grid by using their own generation, by purchasing the required synchronized reserve under contract with another party or by buying it on the synchronized reserve market.

D. Reliability Pricing Model (RPM)

The purpose of the RPM is to provide a long-term pricing signal for capacity resources and Load Serving Entity (LSE) obligations that is consistent with the PJM Regional Transmission Expansion Planning (RTEP) Process. The RPM includes a Base Residual Auction (BRA) that is held during the month of May three (3) years prior to the start of the delivery year. In the RPM, the cost of procurement is allocated to LSEs through a Locational Reliability Charge in the case of an increase in the region's unforced capacity obligation or to resource providers that caused additional resources to be procured.

IV. Financial Transmission Rights (FTR)

PJM also operates a market for financial transmission rights (FTRs) to assist market participants in hedging price risk when delivering energy on the grid [4]. They are financial instruments that entitle the holder to a stream of revenues (or charges) based on the hourly congestion price differences across a transmission path in the Day-Ahead Market.

A. Fundamentals of FTR Market

The FTRs provide a hedging mechanism that can be traded separately from transmission service. This gives all market participants the ability to gain price certainty when delivering energy across PJM.

Market participants can obtain FTRs in several ways:

• They can bid for them in PJM's annual auction, in which FTRs for the entire transmission capability of the system are available.

• They can bid for them in the monthly balance of planning period auctions at which leftover capacity after annual auction is available..

• They can bid for them in the Long Term FTR Auctions in which FTRs are effective for up to three years after current planning year.

• They can bilateral trade them in the secondary market in a transaction with another market participant.

Market participants can manage their FTR portfolios by using the eFTR tool. Participants use eFTR to post their FTRs for bilateral trading as well as to participate in the scheduled FTR auctions.

FTRs allow market participants to offset or bypass the congestion charges that result from the use of locational marginal prices (LMP) in the PJM market. The availability of FTRs can reduce risk and provide price certainty.

An FTR's economic value is based on the megawatt reservation level multiplied by the difference between the congestion price of the source and sink points in the day-ahead market. These congestion price differences reflect opportunity costs of the transmission paths. FTRs are financially binding and can either be a benefit or a liability to the holder.

They are a benefit when the designated path is in the same direction as the congested flow. This occurs when the sink node congestion price is greater than the source node congestion price in the day-ahead market. FTRs are a liability when the inverse occurs. The holder of an obligation FTR must pay for holding the FTR when the sink node congestion price is less than the source node congestion price in the day-ahead market.

FTRs may be acquired in different ways depending on the market design. In the PJM market, transmission service customers who pay the embedded cost of the transmission system have the option of requesting ARRs. ARRs are Auction Revenue Rights that can be used to offset costs for guaranteed FTRs of the same path in the Annual Auction. These revenue rights can also be used to offset costs for other purchased FTRs or they can just be held as a source of revenue. The revenues from the Annual FTR Auction are paid to the holders of ARRs. FTRs can also be acquired through the centralized FTR auction market. All ARR and FTR requests submitted (whether through transmission service requests or the auction) must pass the SFT prior to being approved. The SFT analysis ensures that the financial entitlements granted through approved

ARR and FTR requests can be simultaneously honored within the existing capability of the transmission grid. Therefore the SFT analysis ensures that the revenue from transmission congestion rentals is adequate under normal system conditions to pay ARR and FTR credits.

The time frame for the 2007/2008 Annual ARR and FTR process is shown in Figure 6.

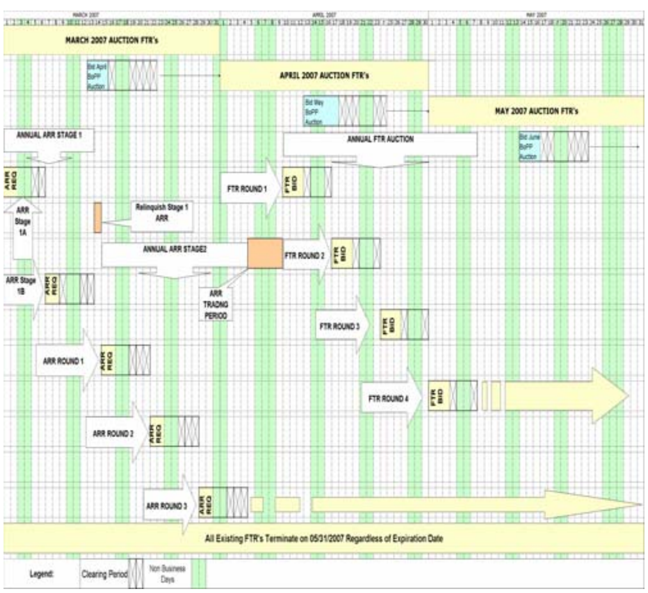

Figure 6 Example of the Annual ARR and FTR frame

FTRs are financial contracts; they do not create a physical right to energy delivery. They operate independently of actual energy deliveries. Their economic value is based on the congestion prices in the Day-Ahead Market for delivery from a specified source to a specified destination.

B. PJM FTR Market Function and Structure

PJM performs the following actions:

• conducts Simultaneous Feasibility Tests (SFTs) on FTRs

• notifies customers of SFT results and FTRs awarded in the FTR Auctions

• initiates, directs, and oversees the FTR Auctions

• incorporates FTRs into market settlements

The architecture of the contingency-constrained FTR auction clearing system is shown in Figure 7. It consists of multiple modules: relational database server, market operator interface (MOI), contingency analysis, sensitivity analysis and optimization-base bid clearing. The simultaneous feasibility test (contingency analysis and sensitivity analysis) module and optimization module are the main components of the application.

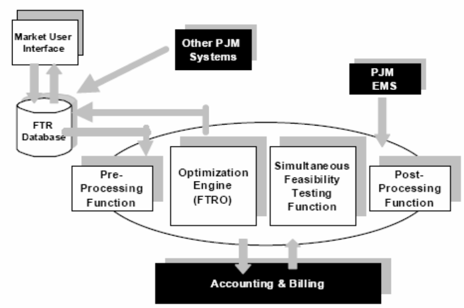

Figure 7 PJM FTR Market Structure

C. Optimization Formulation

The FTR auction is a security-constrained optimization problem. For a pre-defined contingency list and monitored elements, an AC load flow is used to perform contingency analysis for optimization-based bid-clearing solution. If the pre-defined contingencies cause security problems, a set of constraints is constructed for a selected number transmission network element rating violations and passes to the optimization module for enforcement in the next iteration. SFT and the optimization module iterate until no new contingency violation is detected. The problem can be described as in (1):

$$\max\left(\sum_{cleared-bids} Price_{bid} \times MW_{bid} - \sum_{cleared-offers} Price_{offer} \times MW_{offer}\right) \quad (1)$$

subject to

- $0 \le MW_{cleared-bid} \le MW_{total\ cleared\ bid}$
- $0 \le MW_{cleared-offer} \le MW_{total\ cleared\ offer}$
- Power flow balance
- Branch flow limits
- Generic constraints
- Contingencies

LMPs are determined by the shadow prices of power flow balance constraints at each bus. The shadow prices are byproducts of the LP solution. In addition, shadow prices corresponding to all other constraints are also available in the

FTR auction solution.

V. Economic Transmission Planning

Managing the future growth of the electric system is an integral part of PJM Interconnection's role as an ISO/RTO. PJM conducts a long-range Regional Transmission Expansion Planning (RTEP) process that identifies what changes and additions to the grid are needed to ensure reliability and the successful operation of the wholesale markets.

The main technical criteria that should drive transmission planning are reliability and congestion. Reliability relates to transmission contingencies and the ability of the system to respond to these issues [5]. NERC reliability regions are shown in Figure 8. Congestion occurs when transmission reliability limitations result in the need to use higher-cost generation than the case without any reliability constraints. Both reliability and congestion are critical and present technical challenges.

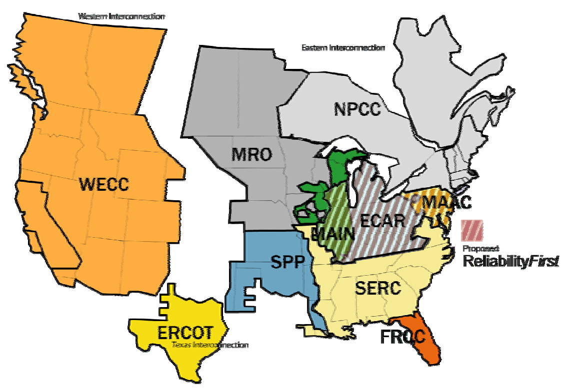

Figure 8 NERC Reliability Regions

For decades, the reliability criteria used by NERC for transmission planning has been "N-1". N-1 has served the industry well but has several challenges when applied to transmission planning today. It is a deterministic nature which means all contingencies are treated equal regardless of how likely they are to occur or severity of consequences. It also can not account for the increased risk associated with a more heavily interconnected and more heavily loaded system.

The RTEP process systematically and objectively evaluates proposed transmission upgrades, generation interconnections and demand-response projects to make sure that compliance with reliability criteria is maintained. The process also includes a mechanism to mandate necessary grid improvements. PJM's planning process began in 1997; its first regional plan was approved in August 2000.

The process accommodates not only expansion projects proposed by transmission owners, typically electric utilities, but also merchant generation and transmission projects that are financed by private investors instead of utilities.

PJM's open and extensive review process ensures that all interested parties, including state regulatory agencies, have an active role in planning for future electricity supply and reliability needs. As part of the RTEP process, projects are reviewed by the PJM Board. Once a project is approved by the board, it is incorporated into the plan.

Under PJM agreements, transmission owners are obligated to build transmission projects that are needed to maintain reliability standards and that are approved by the board.

The board approved the RTO's first 15-year regional plan in June 2006. In that plan, the board authorized the construction of $1.3 billion in electric transmission upgrades by 2011. It also approved construction of a 240-mile, 500-kilovolt (kV) transmission line from southwestern Pennsylvania to Virginia. In 2007, the board approved an additional $2.9 billion in transmission upgrades and additions, including two major new transmission lines.

To date, transmission investments authorized under the PJM plan since 2000 total more than $7 billion, with about 19,400 megawatts of new generation being interconnected to the PJM grid.

Project justification during the planning process needs to incorporate the production information. Analysis tools that merge production cost analysis with transmission system constraints to aid the planning in getting insights into the economic value of projects.

PJM's RTEP process includes an economic planning component. It is designed to develop cost-effective solutions to alleviate congestion on the transmission system.

Open transmission access has been standing at the center of electricity deregulation. A mechanism that allows for efficient allocation of transmission access rights has been sought in every market design. For planning on a regional or national level, probabilistic methods show promise in managing the scope of studies. By using this non-deterministic method, the probabilistic reliability evaluation and economic analysis can be done. The parameters will include load growth, fuel cost, emission costs, discount rate(s), and potential future new generation or generation retirements.

The PJM Economic Planning Process still is under development as part of market-efficiency initiatives and is evolving through an extensive stakeholder process. PJM will initiate the Market Efficiency analysis to accomplish the following objectives:

1) Determine which reliability upgrades, if any, have an economic benefit if accelerated or modified; and,

2) Identify new transmission upgrades that may result in economic benefits, using the methodology described in the Market Efficiency business rules.

3) Identify economic benefits associated with "hybrid" transmission upgrades. Hybrid transmission upgrades include proposed solutions which encompass modification to reliability-based enhancements already included in RTEP that when modified would relieve one or more economic constraints. Such hybrid upgrades resolve reliability issues but are intentionally designed in a more robust manner to provide economic benefits in addition to resolving those reliability issues.

VI. Conclusions

This paper discusses fundamental features of the PJM energy market, e.g. day-ahead, real-time, FTR issues as well as the economical planning and operation in PJM wholesale market.

Recent development of electricity market designs has shown a clear trend of convergence toward a high degree of liquidity market. These include LMP based energy market, short and long term FTR market, ancillary markets, etc. And these markets have been proven to work successfully in PJM.

In all, PJM coordinates the continuous buying, selling and delivery of wholesale electricity through the Energy Market. In its role as market operator, PJM balances the needs of suppliers, wholesale customers and other market participants and monitors market activities to ensure open, fair and equitable access.

VII. References

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