CASE 1

Merger Analysis in Restructured Electricity Supply Industries: The Proposed PSEG and Exelon Merger (2006)

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INTRODUCTION

On December 20, 2004, the Exelon Corporation (Exelon) and the Public Service Enterprise Group Incorporated (PSEG) announced a merger agreement to create Exelon Electric and Gas; the parties claimed that it would be the largest utility in the United States.[1] The merged entity would serve close to seven million electricity customers and two million natural gas customers in Illinois, New Jersey, and Pennsylvania and would own slightly more than 51,000 megawatts in generation capacity, with 40 percent of it powered by nuclear energy.

Exelon's expertise in operating nuclear generation facilities and PSEG's ownership of 3500 megawatts (MW) in nuclear capacity were cited by the parties as an important factor driving the merger.[2] The merger agreement was accompanied by a separate operating services contract that

[*]Frank A. Wolak assisted the U.S. Department of Justice in its analysis of the proposed merger. The views expressed herein are not purported to represent those of the U.S. Department of Justice.

[1]See http://phx.corporate-ir.net/phoenix.zhtml?c=124298&p=irol-newsArticle&ID=656265&highlight= for the merger announcement that contains this statement.

[2]See http://phx.corporate-ir.net/phoenix.zhtml?c=124298&p=irol-newsArticle&ID=656265&highlight= for the merger announcement that contains this statement.

specified that Exelon would manage plant operations at PSEG's nuclear generation units regardless of the ultimate outcome of the merger.[3]

Exelon owns PECO, Pennsylvania's largest utility, which serves approximately 1.6 million electricity customers in the city of Philadelphia and surrounding counties and serves 480,000 natural gas customers outside of Philadelphia.[4] PSEG owns Public Service Electric and Gas Company (PSE&G), which serves 2.1 million electricity customers and 1.7 million natural gas customers in New Jersey. The service territories of PECO and PSE&G are adjacent to one another, and a substantial fraction of the generation capacity owned by these firms is located within or near these two service areas. Consequently, the combination of PECO and PSE&G could reduce competition in the market for wholesale electricity to serve electricity consumers in the PECO and PSE&G service areas and in substantial parts of the remainder of the PJM Interconnection, the wholesale market that covers some or all of the states of Pennsylvania, New Jersey, Maryland, Delaware, North Carolina, Michigan, Ohio, Virginia, West Virginia, Indiana, and Illinois.

Until the electricity industry restructuring of the 1990s and early twenty-first century, most mergers in the electricity supply industry did not raise significant antitrust concerns. The industry was composed of vertically integrated geographic monopolies, each of which was responsible for the production, transmission, distribution, and sale of all electricity in its service territory. Each firm had a legal obligation to serve all customers in its service territory at prices set by a state public utility commission. These prices were set to allow the firm an opportunity to recover all prudently incurred costs of serving its customers, including a return on capital invested by the firm's shareholders. Consequently, many of the usual mechanisms for a merger to create or enhance market power and thus raise prices to final consumers were not available to electricity suppliers because of this state-level regulation of retail prices and service quality.[5]

Electricity industry restructuring replaced cost-based regulation with market mechanisms as the primary means for setting wholesale electricity prices. Mergers between generation unit owners that sell into wholesale

[3]See http://phx.corporate-ir.net/phoenix.zhtml?c=124298&p=irol-newsArticle&ID=656265&highlight= for the merger announcement that contains this statement.

[4]Exelon also owns ComEd, which provides electricity to 5.2 million customers in northern Illinois, including the city of Chicago.

[5]Vertically integrated electric utilities operating in multiple states created significant challenges for the individual state regulatory commissions. Each state could ensure only that all of the prices that it set allowed the firm an opportunity to recover the costs of serving customers within its boundaries. The larger were the number of states in which a vertically integrated electric utility operated, the more challenging was the effort to ensure that the prices set by all of the state regulatory commissions did not allow the firm to earn total revenues in excess of all prudently incurred production costs. For this reason, mergers involving multistate utilities in the former vertically integrated monopoly regime could cause antitrust harm.

markets can raise significant antitrust concerns because a firm that owns a larger share of the total generation capacity available to serve demand has a greater incentive to withhold output to raise the market-clearing price. The California electricity market during the period of June 2000 to June 2001—documented in Borenstein, Bushnell, and Wolak (2002) and Wolak (2003c)—illustrates the potential impact of the exercise of unilateral market power on short-term wholesale electricity market prices.

Combining two electricity suppliers that own a substantial amount of generation capacity in close proximity to one another—which would have been the final outcome of the proposed merger of Exelon and PSEG—could significantly reduce competition in a bid-based wholesale electricity market. The California electricity market experience suggests that small changes in competitive conditions can lead to substantial wealth transfers from consumers to producers as well as significant deadweight losses. The parties recognized the need to remedy any potential competitive harm associated with the merger.[6] In their initial merger application to the Federal Energy Regulatory Commission (FERC), the parties proposed to sell a total of 2900 MW of fossil fuel generation facilities and 2600 MW of nuclear facilities in a virtual divestiture to address the potential economic harm associated with the merger.[7] Around the time that the merger was announced, the editor of a leading industry publication argued that the primary point of debate between the merging parties and reviewing agencies was likely to be over how best to remedy the effect of the merger on wholesale competition in the PJM Interconnection wholesale electricity market (Radford 2005).

A bid-based short-term market that sets day-ahead and real-time wholesale prices for each hour of the day is a defining feature of formal wholesale electricity markets. These markets yield a rich source of data on the willingness to supply of each producer that can be used to simulate alternative postmerger and postdivestiture market outcomes. The history of state-level regulation of the industry provides information on the technical characteristics of the "fleet" of generation units owned by each firm necessary to construct an accurate estimate of its marginal cost function. Bid-based wholesale markets have market rules that are filed with the FERC—the U.S. wholesale market regulator—that specify precisely how the actions of market participants translate into revenues received and costs incurred. This clarity and detail in the market rules make it unnecessary for the economic analyst to make untestable assumptions about how the market

[6]See pp. 20–21 of NJBPU (2005).

[7]See http://phx.corporate-ir.net/phoenix.zhtml?c=124298&p=irol-newsArticle&ID=670685&highlight= for the press release proposing these divestiture packages. The concept of a "virtual divestiture" is explained in the text later in this chapter.

operates in simulating postmerger and postdivestiture market outcomes. These three features of wholesale electricity markets allow a rich quantitative analysis of the impact of mergers and proposed remedies with few economic modeling assumptions besides expected profit-maximizing behavior by firms.

The remainder of the chapter presents a graphical discussion of this quantitative approach to merger analysis in wholesale electricity markets and then applies several insights from it to the proposed PSEG and Exelon merger. The next section describes the PJM Interconnection, the various agencies charged with analyzing the competitive impacts of the merger, and the rationale for the merger offered by the parties. The following section describes important aspects of electricity production and bid-based wholesale electricity markets that are necessary to understand the quantitative approach to merger analysis. A graphical approach is used to convey the basic economic theory and intuition for the quantitative analysis. This discussion is followed by a description of the formal merger review process, including the initial proposal of the merging parties and the outcome of the review process at each agency, including the ultimate outcome of the proposed merger and possible reasons for it. The chapter concludes with a discussion of the lessons that future merging parties in a bid-based wholesale electricity market might learn from the outcome of this proposed merger.

INDUSTRY AND INSTITUTIONAL BACKGROUND FOR MERGER ANALYSIS

This section first describes important features of the PJM Interconnection wholesale market and the characteristics of the two merging parties. This is followed by a description of the four agencies reviewing the merger and the position of the merging parties.

Industry Background for Merger Analysis

Figure 1-1 contains a map of the PJM Interconnection, which is the largest wholesale electricity market in the United States in terms of the total megawatts of generation capacity within its boundaries (approximately 165,000 MW) and the level of peak demand (approximately 145,000 MW). The vast majority of generation units owned by PSEG are contained in the region labeled "PSE&G" in Figure 1-1. The majority of generation units owned by Exelon are in the regions labeled "PECO" and "ComEd." The shared border between the PSE&G (in New Jersey) and PECO (in Pennsylvania) territories suggests that without an appropriate package of generation unit divestitures, the merged entity could have a greater incentive and ability to increase wholesale electricity prices, particularly in parts of the PJM Interconnection that contain the PSE&G and PECO service territories.

Table 1-1 lists the characteristics of the two merging parties taken from the PSEG website at the time of the merger. As of the end of 2003, Exelon owned 34,467 MW of generation capacity, and PSEG owned 17,117 MW,

FIGURE 1-1 Map of PJM Interconnection

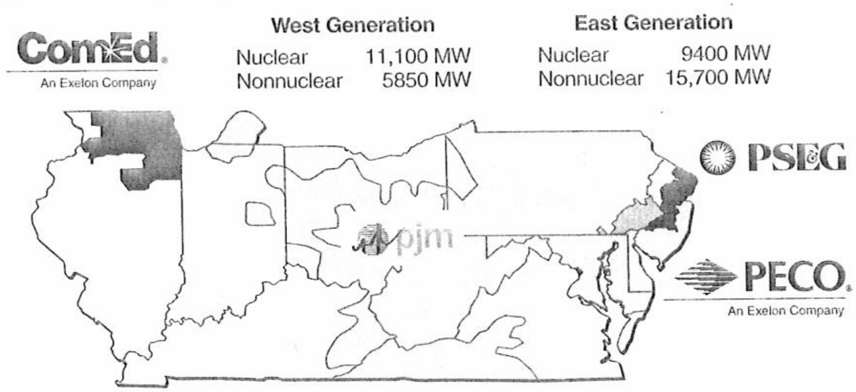


TABLE 1-1
Characteristics of the Merging Parties

	Exelon 2003	PSEG 2003	Combined
Electric Customers	5,100,000	2,000,000	7,100,000
Gas Customers	460,000	1,600,000	2,060,000
U.S. Generation Assets (MW)*	34,467	17,117	51,584
Nuclear Generation (MW)	16,943	3510	20,453
Assets, Revenues, and Income (billions of dollars)			
Total Assets	$41.9	$28.1	$70.0
Total Revenues	$15.8	$11.1	$26.9
Net Income**	$1.7	$0.9	$2.6

*Projected 2004 year end.

**Income from continuing operations.

Source: "PSEG and Exelon: Creating the Premier Utility of Tomorrow." (http://www.pseg.com/media_center/pdf/CommerceMagazine07–05.pdf).

for a combined total of 51,584 MW. Exelon, which specializes in the operation of nuclear generation facilities, owned 16,943 MW of nuclear generation.[8] PSEG owned 3510 MW of nuclear generation, so that (absent divestitures) the combined entity would own 20,453 MW of nuclear generation assets.

The parties estimated that the merged entity would have had total assets of close to $80 billion and annual revenues of more than $27 billion in 2004.[9] As Radford (2005) notes, this would make the new firm more than 25 percent larger in terms of total assets than the second-largest electricity utility in the United States. As Table 1-1 demonstrates, both PSEG and Exelon also serve a significant number of retail natural gas customers. However, the combined entity would have almost three and a half times more electricity customers than natural gas customers.

The natural gas companies owned by PSEG and Exelon would remain vertically integrated utilities subject to state-level retail price regulation following the merger. It appears that the major reviewing agencies did not believe that the merger would increase the difficulty of regulating the retail price of natural gas charged by the utilities owned by the merged entity. The U.S. Department of Justice (DOJ) complaint opposing the merger (as it was originally proposed) stated that "Exelon's merger with PSEG would eliminate competition between them and give the merged firm the ability and incentive to raise wholesale electricity prices . . ." but did not mention harm to wholesale or retail natural gas markets.[10] The FERC investigation of the merger focused almost exclusively on assessing the impact of the combination on wholesale electricity prices (see FERC 2005).

Reviewing Agencies and Standards for Review

Four agencies assessed the competitive impacts of the proposed merger: the federal wholesale electricity regulator (FERC), the state public utility commissions in the states of New Jersey and Pennsylvania, and the DOJ.[11] Both the federal and state regulatory commissions are legally

[8]Exelon was formed in October 2000 by the merger of Unicom of Chicago (which owned ComEd) and PECO. A major motivation for that merger was to consolidate the nuclear operations of the two merging parties.

[9]"PSEG and Exelon: Creating the Premier Utility of Tomorrow" (http://www.pseg.com/media_center/pdf/CommerceMagazine07-05.pdf).

[10]This complaint is available at http://www.usdoj.gov/atr/cases/f216700/216785.htm.

[11]The Illinois Commerce Commission, the Illinois public utility regulatory commission, informed the merging parties that it did not have jurisdiction over the merger and thus that its approval was not required.

required to apply a "public interest" standard, which is different from the standard applied in the Horizontal Merger Guidelines (HMG), in deciding whether to approve the merger. The HMG focus on assessing whether the merger will "create or enhance market power" or "facilitate its exercise."

The public interest standard of the FERC considers three factors to assess a merger: (1) the effect on competition, (2) the effect on rates, and (3) the effect on regulation. The effect on competition is essentially the HMG competitive effects assessment. The effect on rates asks whether the merger will affect the rates for any wholesale power or transmission customer. This assessment is closely related to the effect-on-competition assessment because if the merger lessens competition, then wholesale prices and rates to some customers are likely to rise. The effect on regulation asks whether the effectiveness of federal or state regulation will be adversely affected by the merger.

The Pennsylvania Public Utility Commission and the New Jersey Board of Public Utilities (NJBPU) have slightly different public interest standards. The Pennsylvania standard requires the merger to provide substantial benefits to Pennsylvania consumers and not to result in anticompetitive or discriminatory conduct or the unlawful exercise of market power. The NJBPU public interest standard requires an assessment of the impact of the merger on competition, rates, employees of the affected public utility, and the provision of safe and adequate utility service, in addition to tangible benefits to New Jersey consumers.

From their public statements, the primary competition concern about the merger by state regulators appears to have been the effect of the combination of generation assets owned by PSEG and Exelon on wholesale market prices and the eventual effect on retail electricity prices in their respective states. The Pennsylvania Public Utilities Commission cited the fact that Exelon agreed to freeze PECO's retail electricity rates through 2010 as a major reason for approving the merger.[12] The NJBPU stated that "the acquisition of PSEG by Exelon would explicitly reduce the number of significant competitors in New Jersey wholesale markets by one . . ." and ". . . absent mitigation or other measures, the currently substantial market shares of each company in the relevant markets raises not merely the potential but rather certainty of significantly higher market concentration and the potential future exercise of market power" (NJBPU 2005). Therefore, based on these public statements and those cited above, the primary competition concern of both state and federal reviewing agencies appeared to be competition in the wholesale electricity market.

[12]See http://www.puc.state.pa.us/General/press_releases/Press_Releases.aspx?ShowPR=1451 for the press release approving the merger.

Position of the Merging Parties

The parties claimed that the merger would provide significant value to customers and shareholders of both companies.[13] Most of these benefits were the result of the increased scale of operations of the combined entity. This was claimed to lead to improved service reliability and greater earnings predictability. Greater service reliability was also claimed as a consumer benefit. The combination of several regulated utility businesses and large, low-variable-cost, and low-emissions generation businesses—primarily the nuclear generation units owned by the two companies—in the PJM Interconnection wholesale electricity market was claimed to provide consistent profitability and stable cash flow growth. All of these benefits accrue to shareholders and may be the result only of increased opportunities for the merged entity to exercise unilateral market power in the wholesale electricity market, rather than the result of any cost savings.

The one potential source of cost savings was the opportunity for Exelon to take over the ownership of PSEG's nuclear "fleet" and implement its management and operation practices at these generation units. Exelon operates the largest nuclear generation fleet in the United States and has implemented a successful nuclear performance program: the Exelon Nuclear Management Model. Data provided by the parties in their merger announcement presentation demonstrated that significant capacity utilization increases and nonfuel production cost reductions were possible at PSEG nuclear facilities from adopting Exelon management practices.[14] In this same presentation, the merging parties argued that every 1 percent increase in the capacity utilization of PSEG's nuclear fleet would result in an additional $12 million in pretax income.

Although these potential cost savings and revenue increases from improved performance of PSEG nuclear facilities were economically significant, working against the claim advanced by the PSEG and Exelon that these synergies could be realized only through a merger was the fact that a separate nuclear operating services contract was signed at the same time as the merger agreement. Under this agreement Exelon supplies senior personnel to manage daily plant operations and implemented the Exelon Nuclear Management Model at PSEG's Hope Creek and Salem nuclear generation facilities. Further evidence against the need for PSEG and Exelon to merge in order for PSEG to realize improvements in operating efficiency is the fact that Exelon staff ran the PSEG nuclear facilities during

[13]See http://phx.corporate-ir.net/phoenix.zhtml?c=124298&p=irol-newsArticle&ID=656265&highlight= for a description of the parties' claimed benefits to shareholders and customers from the merger.

[14]The two figures on p. 22 of the presentation on December 20, 2004 (http://media.corporate-ir.net/media_files/irol/12/124298/pdfs/EXC_PSEG_AnalystPres_122004.pdf) show noticeably higher capacity factors and lower nonfuel production costs for Exelon versus PSEG nuclear generation units.

2005 and 2006 under the operating agreement and realized significant operating efficiency improvements relative to those achieved the year before the agreement was signed.[15]

Without divestitures the merged entity would control roughly one-third of the generation capacity in the PJM Interconnection. Because of the close geographic proximity of the PECO and PSEG service territories, the merged entity would control a substantially larger fraction of the generation capacity in the portion of the PJM Interconnection—PJM East—that contains these two service territories. There is a large transmission interface that divides the remainder of PJM from PJM East: the Eastern Interface. A substantial number of the low-variable-cost generation units is located west of the Eastern Interface, and these units typically export electricity to PJM East. Consequently, when there is congestion on the Eastern Interface, the merged entity would face competition from a substantially smaller number of generation unit owners.

Based on the publicly stated preconditions for approval of the merger by each of the reviewing agencies, there appears to be disagreement among them over how to ensure that the merger did not harm competition in wholesale electricity in the PJM Interconnection. For example, the FERC required less fossil fuel capacity to be divested relative to the amount required by the DOJ. However, the FERC required virtual divestiture of nuclear generation capacity, whereas the DOJ did not. The NJBPU never stated its final position on the necessary amount of divestiture, but in August 2006 the New Jersey public advocate proposed an additional divestiture of more than 2500 MW of fossil fuel plants beyond the DOJ settlement.[16] Consequently, the specific points of disagreement on how to remedy the competitive impacts of the merger appeared to be (1) the total MW of generation capacity to be divested, (2) the variable costs and location of the MW of capacity to be divested, and (3) whether a virtual or physical assets sale was sufficient to address these competition concerns. The next section introduces the key features of the electricity supply industry that are necessary to analyze of the competitive impacts of a merger in a bid-based wholesale electricity market.

TOOLS FOR ANTITRUST ANALYSIS IN WHOLESALE ELECTRICITY MARKETS

There are four segments of the electricity supply industry: (1) generation, (2) transmission, (3) distribution, and (4) retailing. These segments differ in

[15]See "PSEG Will Take Nuclear Operations But Hire Exelon Staff That Raised Output," *Electricity Utility Week*, December 25, 2006, p. 27, for a description of the operating efficiency improvements achieved during 2005 and 2006 relative to 2004.

[16]See "Exelon and PSEG Silent on Counteroffer to Merger Plan from N.J. Public Advocate," *Electric Utility Week*, August 14, 2006, p. 1.

the extent to which the technology of production favors supply by a single geographic monopoly.

Generation is the conversion of heat or kinetic energy such as fossil fuel, nuclear fuel, running water, wind, or solar energy into electrical energy.[17] Transmission is the high-voltage transportation of electricity from generation facilities to the local distribution network. Distribution is the low-voltage delivery of electricity to final consumers. Retailing is the sale of electricity to final consumers. The electricity retailer purchases wholesale electricity and pays for the cost to use the transmission and local distribution networks that deliver the electricity to final consumers.[18]

In a wholesale market, all generation unit owners within the geographic confines of the wholesale market compete to provide wholesale electricity to retailers, who then sell it to final consumers using the local distribution network. All generation unit owners and retailers in this geographic area have access to the transmission network at regulated prices. All retailers pay for local distribution network services at a regulated price set by the state public utility commission.

Wholesale electricity markets function like wholesale markets for other products with a number of very important exceptions that are due to the unique characteristics of electricity. First, supply must equal demand at every instant in time and at every location in the transmission network. Second, all electricity produced must be delivered through a transmission network that has finite capacity to transfer electricity between any two locations. Third, the production of electricity is subject to severe capacity constraints in the sense that a generation unit can produce only a finite amount of energy within an hour.[19] Fourth, electricity is very costly to store, so that virtually all of what is consumed must be produced during that same time period. Finally, the real-time demand for electricity is close to perfectly price-inelastic because the retail price charged to virtually all final consumers does not vary with the hourly wholesale price.

A real-time wholesale market operator is required to ensure that all of these technical requirements for the reliable supply of electricity to final consumers are met. Although the details of wholesale electricity market operation are extremely complex, the basic features can be described in simple economic terms. Each day generation unit owners submit to the market operator their willingness to supply energy from their generation

[17]Wolak (1999) discusses the technology and organization of production in the electricity supply industry and a comparison of the early experience with wholesale electricity markets.

[18]Joskow (1989) provides an insightful but accessible history of the U.S. electricity supply industry and the regulatory failures that led to industry restructuring. Joskow (1997) discusses the rationales offered for the industry restructuring process chosen in the United States.

[19]A unit with a nameplate capacity of 200 MW can typically produce slightly more than 200 MWh (on the order of 10 percent) within an hour by operating beyond the unit's minimum variable cost level of output. Operating in this range also significantly increases the risk that the unit will fail.

units during the following day, as a function of the market price for each hour of the following day.

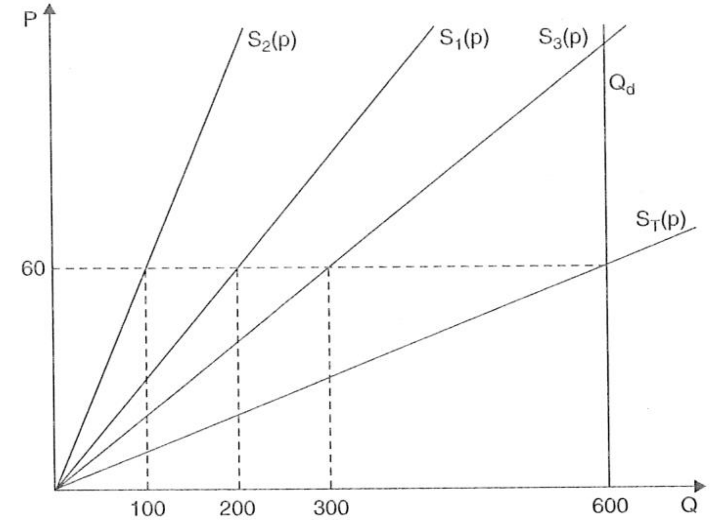
For all wholesale electricity markets in the United States, these willingness-to-supply functions are step functions, with the height of each step equal to the offer price at which the owner of the generation unit is willing to supply an amount of output equal to the length of the step. For example, in the PJM Interconnection, each supplier is allowed to submit up to ten price levels and associated quantity increments for each generation unit each day. The ability to submit different price offers for different levels of output from the generation unit accounts for the fact that the variable cost of producing electricity can vary with the level of output in the current period and in previous time periods.[20] Because each generation facility is typically composed of multiple generation units, and firms usually own many generation facilities, these firm-level willingness-to-supply curves are composed of hundreds of price levels and quantity increments. Exelon and PSEG each own more than one hundred generation units, which implies that each company sets more than one thousand price levels and quantity increments in the willingness-to-supply curves that it submits to the PJM Interconnection wholesale market operator each hour of the day. To simplify the subsequent graphical analysis, for the remainder of this chapter these willingness-to-supply functions and all marginal cost functions are assumed to be smooth.

In the absence of congestion in the transmission network, the market operator can take the willingness-to-supply curve from each generation unit owner and compute an aggregate supply curve for each hour of the following day. A single market-clearing price is then determined by the price at which the aggregative willingness-to-supply curve intersects the aggregate demand for that hour. All generation unit owners with offer prices less than the market-clearing price are obligated to supply the total megawatt hours (MWh) of energy offered at or below this price.

Figure 1-2 plots the firm-level willingness-to-supply curves for a wholesale electricity market with three suppliers. The vertical axis denotes the market price and the horizontal axis the quantity that each firm is willing to supply at that price. Let $S_1(p)$, $S_2(p)$, and $S_3(p)$ equal the willingness-to-supply curves of firms 1, 2, and 3, respectively. At a price of \$60/MWh, firm 1 is willing to supply 200 MWh, firm 2 is willing to supply 100 MWh, and firm 3 is willing to supply 300 MWh. The aggregate willingness-to-supply curve, $S_T(p)$, is the sum of the amounts that the three firms are willing to supply at each possible price. The vertical line denotes the market demand, Q_d, which is equal to 600 MWh. The price at the intersection of the

[20]Wolak (2007) presents evidence from generation unit-level bidding and operating behavior in the Australian electricity market that unit-level marginal costs vary with the level of output in the current and neighboring time periods of the day.

FIGURE 1-2 Aggregate Willingness-to-Supply Curve and Market-Clearing Price



market demand with the aggregate willingness-to-supply curve is the market-clearing price, which is \$60/MWh.

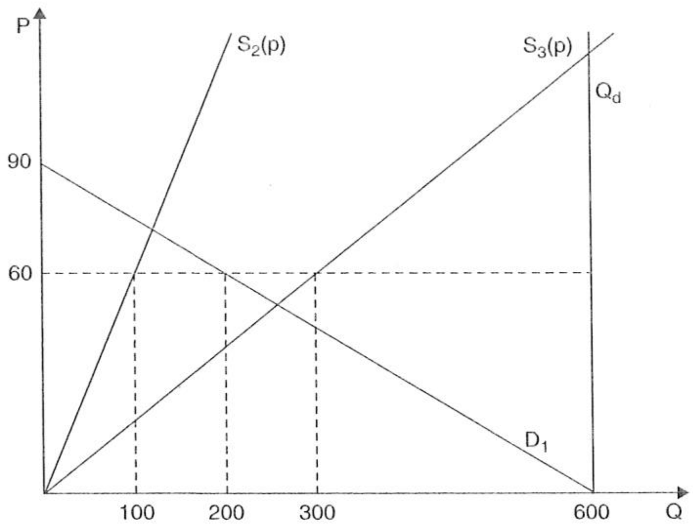
According to the market rules, the revenue of each firm is the market-clearing price times the amount that it produces. In this case, firm 1 receives \$12,000 in revenues, the market-clearing price of \$60/MWh times 200 MWh, the amount it was willing to supply at that price. Firm 1's profits are the difference between this total revenue and its total cost of producing 200 MWh. The revenues and profits of firms 2 and 3 are determined in an analogous manner.

To analyze a proposed merger in a bid-based wholesale electricity market it is necessary to understand how each firm constructs its willingness-to-supply curve that it submits to the wholesale market operator and how that curve enters the aggregate willingness-to-supply curve that determines the market-clearing price. The essential intuition for this process can be conveyed using the standard model of a profit-maximizing monopoly.[21]

The first step is to construct a measure of firm-level unilateral market power using the market demand and the willingness-to-supply functions of all other firms besides the one under consideration. Let firm 1 be the

[21]Wolak (2000, 2003a, and 2007) presents a general model of expected profit-maximizing bidding behavior in wholesale electricity markets with step function willingness-to-supply curves that is the foundation for the graphical analysis presented here.

FIGURE 1-3 Construction of Residual Demand Curve of Firm 1

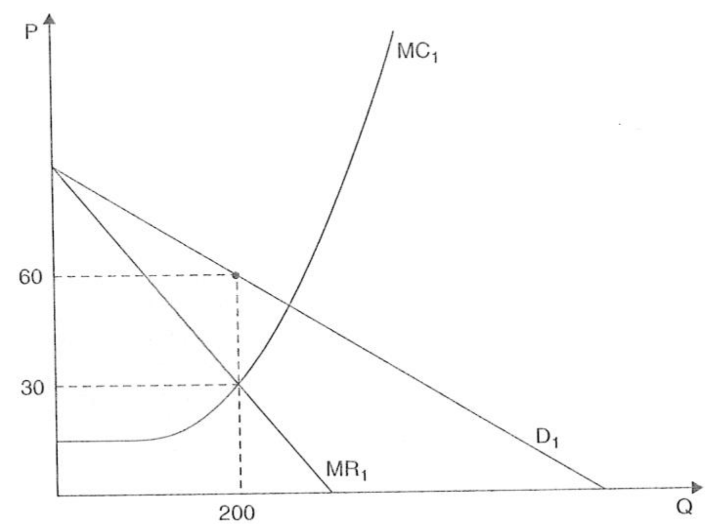


supplier whose expected profit-maximizing willingness-to-supply curve is being constructed and assume for the moment that firm 1 can observe the market demand and the willingness-to-supply curves of firms 2 and 3. This is clearly not the case in reality because all firms must submit their willingness-to-supply curves at the same time, and the value of the market demand is typically unknown when they do. However, this assumption simplifies the presentation and will be relaxed once a number of important concepts have been introduced.

Figure 1-3 depicts the construction of what is called the "residual demand curve" facing firm 1. At each price, firm 1's residual demand is the amount of market demand left for firm 1, given the willingness-to-supply curves of all its competitors. In Figure 1-3, firm 1's residual demand is computed by taking the difference between the market demand and the amounts that firms 2 and 3 are willing to supply at that price. At a price of $60/MWh, firm 2 is willing to supply 100, and firm 3 is willing to supply 300, so the residual demand facing firm 1 is 200, the difference between the market demand of 600 and the sum of the willingness-to-supply quantities of firms 2 and 3. The curve D_1 is the residual demand curve for firm 1 that results from applying this procedure for all prices between $0/MWh and $90/MWh.

The theory of profit-maximizing behavior by a monopoly yields the price that maximizes firm 1's profits, given this residual demand curve, which depends on the market demand and willingness-to-supply curves of firm 1's competitors. Figure 1-4 reproduces firm 1's residual demand curve

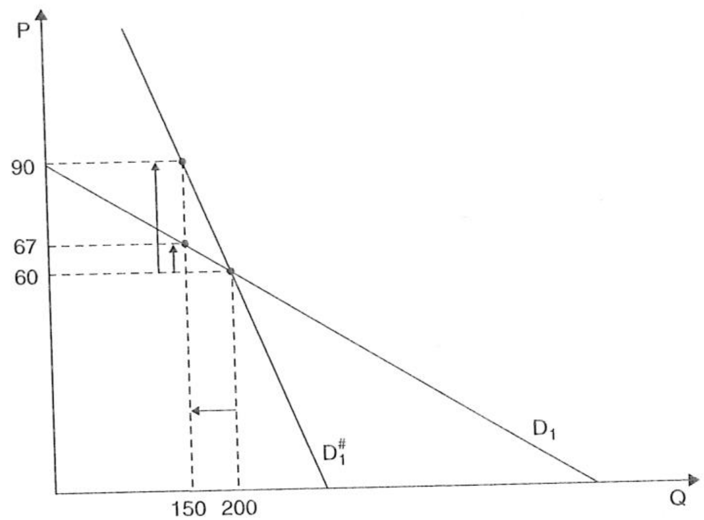
FIGURE 1-4 Calculation of Best-Reply Price and Quantity for Firm 1



from Figure 1-3, D_1, and adds the marginal revenue curve, MR_1, associated with this residual demand curve, along with firm 1's marginal cost curve, MC_1. A profit-maximizing monopolist produces at the level of output where marginal revenue equals marginal cost, $MR_1 = MC_1$, which implies that firm 1 produces 200 MWh. If firm 1 produces 200 MWh, its residual demand curve yields a market-clearing price of $60/MWh. Firm 1's variable profit for this residual demand curve and marginal cost function combination equals the shaded area above its marginal cost curve and below the market-clearing price of $60/MWh. Firm 1 cannot obtain higher profits at any other price or level of output, given the willingness-to-supply curves of its competitors and the market demand, than it does at this price and quantity pair. For this reason, the price and quantity pair ($60/MWh, 200 MWh) is called the "best-reply" price and quantity pair for firm 1 for the residual demand curve realization D_1.

As noted above, the construction of firm 1's expected profit-maximizing willingness-to-supply function is complicated by the fact that it does not know the actual residual demand curve realization that it will face when it submits this function to the market operator. However, firms are typically able to observe the level of market demand and the willingness-to-supply curves of their competitors after the market closes for the day. Although the aggregate demand for electricity varies considerably across hours of the day, week, or year, it can be forecast very accurately on a day-ahead basis. The physical operating characteristics and availability of all generation units in the wholesale market are usually known to all market participants

FIGURE 1-5 Form of Residual Demand Curve and Price Increase from Withholding Output



at the time that they submit their willingness-to-supply curves. These facts and the availability of previous market demand and willingness-to-supply curves provide valuable information about the set of possible residual demand curves that each firm might face and the probability that it will face each of these residual demand curves.

A firm's residual demand curve can be used to construct a summary measure of its *ability* to raise the market price by its unilateral actions. Figure 1-5 graphs two possible residual demand curves for firm 1, D_1, and one that is much steeper, $D_1^\#$. Both curves pass through the price and quantity pair ($60/MWh, 200 MWh). If firm 1 faced D_1, by selling 50 MWh less, reducing its output from 200 MWh to 150 MWh, the market-clearing price would increase to $67/MWh. If firm 1 instead faced $D_1^\#$, by selling 50 MWh less it would raise the market-clearing price substantially, from $60/MWh to $90/MWh. Consequently, a supplier that faces a steeper residual demand curve has a much greater ability to raise the market price by withholding output than does a supplier that faces a flatter residual demand curve.

The steepness of a residual demand curve can be measured in a way that does not depend on the units used to measure prices and quantities. The price elasticity of demand is defined as the percentage change in the residual demand at price P that results from a 1 percent increase in this price:

$$\varepsilon(P) = \frac{\text{Percentage Change in Residual Demand}}{\text{Percentage Change in Price}}.$$

The inverse of this demand elasticity measures the percentage change in the market-clearing price that results from a 1 percent reduction in the firm's output at price P. The absolute value of this inverse elasticity can be thought of as a measure of the *ability* of the firm to raise the market-clearing price by reducing its willingness to supply electricity.[22]

All of the characteristics of wholesale electricity markets described above tend to make the elasticity of the residual demand curves faced by large suppliers extremely small in absolute value, which implies extremely large inverse elasticities and very large market-clearing price increases from that supplier's withholding a small percentage of its output. Typically, the greater is the share of total generation capacity owned by a supplier, the smaller is the absolute value of the elasticity of the residual demand curve it faces and the greater is its incentive to raise prices through its unilateral actions. Thus, a supplier that owns a large fraction of the total available capacity is likely to be able to raise prices by more than can a smaller supplier, if both suppliers withhold, say, 10 percent of their generation capacity.

There are actions that electricity retailers and state public utility commissions can take to limit the incentive of large suppliers to exploit their unilateral ability to raise market-clearing prices in a bid-based, short-term wholesale market. The most important is the amount of fixed-price forward contract obligations between the electricity supplier and electricity retailers. The next section explains how these fixed-price forward contracts affect the incentive of suppliers to raise prices in the short-term market. For this reason, we believe that they should play a crucial role in analyzing the competitive effects of mergers in bid-based wholesale markets.

Impact of Fixed-Price Forward Contracts on Supplier Behavior

To ensure a reliable supply of wholesale electricity at a reasonable price, electricity retailers sign fixed-price forward contracts that guarantee the price at which they can purchase a fixed quantity of electricity. Let P_c equal the price at which the supplier agrees to sell energy to an electricity retailer and Q_c equal the quantity of energy sold at that price. This contract is negotiated in advance of the date that the generation unit owner will supply the energy, so that the values of P_c and Q_c are predetermined from the perspective of the supplier's behavior in the short-term wholesale market.

It is straightforward to demonstrate that for the same residual demand curve realization, the larger are a supplier's fixed-price forward

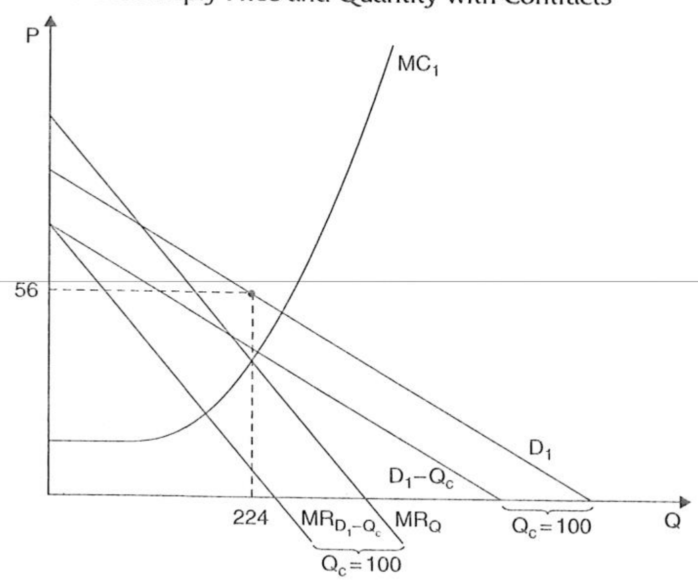
[22]Wolak (2003b) computes hourly residual demand elasticities for the five largest suppliers in the California wholesale electricity market to understand changes in their bidding behavior between the summers of 1998 and 1999 and the summer of 2000 when wholesale electricity prices in California rose dramatically.

contract obligations, the lower will be the price that it finds profit-maximizing because the firm earns only the short-term market price on the difference between its actual production and its forward contract quantity. Therefore, the revenue increase from raising the short-term price is smaller when the firm's forward contract quantity is larger relative to its actual production.

Figure 1-6 reproduces the residual demand curve and marginal cost curves for firm 1 from Figure 1-4. Suppose that firm 1 has a fixed-price forward contract obligation of 100 MWh. Firm 1's level of actual output still determines the market-clearing price set by its residual demand curve. For example, if firm 1 produces 200 MWh, the market-clearing price would be \$60/MWh, as in Figure 1-4. However, this forward contract obligation alters firm 1's revenues because it receives the \$60/MWh market-clearing price for only 100 MWh. The remaining 100 MWh (of the 200 MWh produced) is sold at P_c, the price in the fixed-price forward contract obligation.

To determine the change in total revenues to firm 1 from withholding 1 MWh of output with 100 MWh of fixed-price forward contract obligations, Figure 1-6 plots firm 1's residual demand curve less its fixed-price forward contract obligations, which are effectively sold at P_c instead of the market-clearing price. The marginal revenue curve for $D_1 - Q_c$, the net-of-forward-contracts residual demand curve facing firm 1, is constructed following the standard approach to constructing marginal revenue curves.

FIGURE 1-6 Best-Reply Price and Quantity with Contracts



To convert $MR_{D_1-Q_c}$, the marginal revenue curve associated with the net-of-forward-contracts residual demand curve, to the marginal curve associated with firm 1's output, shift $MR_{D_1-Q_c}$, to the right by the amount of firm 1's fixed-price forward contract forward obligations. This curve is plotted as MR_Q, and comparing it with MR_1 in Figure 1-4 reveals that it is uniformly higher at every level of output, which implies a point of intersection of MR_Q with MC_1 at a higher level of output than the 200 MWh shown in Figure 1-5.

The profit-maximizing level of output for firm 1 for the residual demand curve D_1 and fixed-price forward contract obligation $Q_c = 100$ shown in Figure 1-6 is 224 MWh, which implies a lower market-clearing price of \$56/MWh. This figure demonstrates the general result that for the same residual demand curve realization, the larger is a supplier's fixed-price forward contract obligation, the larger is its best-reply output level and the lower is its best-reply price. Extending this logic to the computation of expected profit-maximizing willingness-to-supply curves implies that for the same distribution of residual demand curves, a larger quantity of fixed-price forward contract obligations leads to a greater willingness to supply output by firm 1 at each possible market price.[23]

The elasticity of a supplier's residual demand curve net of its fixed-price forward contract obligations measures its *incentive* to raise prices in the short-term market. Let $\varepsilon^C(P)$ denote this magnitude, which is defined as the percentage change in the difference between the firm's residual demand at price P and its forward contract position brought about by a 1 percent increase in price. If the firm has a positive amount of fixed-price forward contract obligations, then a given change in the firm's residual demand as a result of a 1 percent increase in the market price implies a much larger percentage change in the firm's net-of-forward-contract-obligations residual demand.

For example, suppose that a firm is currently selling 100 MWh but has 95 MWh of forward contract obligations. If a 1 percent increase in the market price reduces the amount that the firm sells by 0.5 MWh, then the elasticity of the firm's residual demand is $-0.5 = $ (0.5 percent quantity reduction) $\div$ (1 percent price increase). The elasticity of the firm's residual demand net of its forward contract obligations is $-10 = $ (10 percent net of forward contract quantity output reduction) $\div$ (1 percent price increase). Thus, the presence of fixed-price forward contract obligations implies a dramatically diminished *incentive* to withhold output to raise short-term wholesale prices, despite the fact that the firm has a significant *ability* to raise short-term wholesale prices through its unilateral actions.

[23]Wolak (2000) uses bid, market outcome, and forward contract quantity data for large suppliers in the Australian wholesale electricity market to demonstrate the sensitivity of a supplier's incentive to influence the short-term market price to the value of its fixed-price forward contract obligations.

In general, $\varepsilon^C(P)$ and $\varepsilon(P)$ are related by the equation:

$$\varepsilon^C(P) = \varepsilon(P)(\text{Actual Output}/[\text{Actual Output} - Q_c]).$$

The elasticity of the firm's residual demand curve net of its fixed-price forward contract obligations is equal to the elasticity of its residual demand curve times the ratio of its total output to its output net of forward contracts. This equation implies that any non-zero value of $\varepsilon(P)$, which quantifies a firm's *ability* to raise market-clearing prices by its unilateral actions, can be translated into a very small *incentive* to raise market-clearing prices (a large value of $\varepsilon^C(P)$ in absolute value) through a large enough value of forward contract obligations relative to actual output.

If all suppliers have significant fixed-price forward contract obligations, then expected profit-maximizing bidding behavior by firms 2 and 3 implies that these firms will submit willingness-to-supply curves with higher levels of output at each possible price than those given in Figure 1-2. The logic used to construct the residual demand curve facing firm 1 described in Figure 1-3 implies that it will now face a much flatter residual demand curve. Figure 1-5 implies that firm 1 will now have a reduced ability to withhold output to raise the market-clearing price because a 1 MWh reduction in output will increase the market-clearing price by less. This logic demonstrates that a high level of fixed-price forward contract obligations for all suppliers in a wholesale market reduces both the unilateral *incentive* and the unilateral *ability* of a supplier to exercise unilateral market power.

Because the magnitude of fixed-price forward contract obligations limits the incentive of suppliers to exercise unilateral market power in the short-term market, one might expect a firm with a significant ability to raise short-term prices to avoid signing forward contracts unless it receives prices that yield the same level of profits that it expects to earn from selling in the short-term market.[24] However, if the buyer of a fixed-price forward contract obligation negotiates this agreement far enough in advance of the date of delivery, then a substantially larger set of firms can compete to supply this product, and the buyer can expect to obtain a more competitive forward contract price. Specifically, if the time between signing the contractual agreement and first delivery of energy from the contract is long enough to allow a new generation facility to enter and provide this energy, the buyer of the fixed-price forward contract will face a very elastic supply of forward contracts at the long-run average cost of a new entrant.[25]

[24]As noted in Wolak (2003c), this logic explains why the prices for the forward contracts negotiated by the state of California during the winter of 2001 for delivery starting in the summer of 2001 were so high. California had to pay for market power that these suppliers expected to be able to exercise in the short-term market during the following two years.

[25]The supply of new fixed-price forward contracts is unlikely to be perfectly elastic because certain generation locations or technologies have a finite capacity for expansion. However, the differences in long-run average cost across locations and technologies are not likely to be very large in the range of output over which competition with existing generation unit owners takes place.

Therefore, at this lengthy time horizon to delivery, existing suppliers are unable to raise forward contract prices above the long-run average cost of a new entrant. Moreover, because of efficiency gains in electricity production over the past twenty-five years, there are many existing generation units with variable costs that are far above the variable cost of the production technology employed by a new entrant.

Therefore, if buyers purchase the vast majority of their energy requirements in fixed-price forward contracts far enough in advance of delivery, they can avoid prices that are the result of significant unilateral market power in the forward contract or short-term market. If all buyers follow this advance purchase forward-contracting strategy, and an existing generation unit owner fails to sign a fixed-price forward contract, then it faces a significant risk of selling its output in a short-term market at very low prices because of the high levels of fixed-price forward contract obligations of the remaining suppliers and the additional new generation units constructed to meet the forward contract obligations sold by new entrants. To avoid this unprofitable outcome in a world where all buyers are purchasing the vast majority of their energy needs far in advance of the delivery date, existing generation unit owners should be willing to sign fixed-price forward contracts at prices that are slightly below the long-run average cost of a new entrant.[26]

The above logic illustrates a very important point in the analysis of any horizontal combination in a wholesale electricity market: If the premerger forward contract obligations of the two merging parties yield close to competitive market outcomes, and a merger takes place that significantly reduces the elasticity of the residual demand curve that the combined firm faces, this could cause the combined firm to reduce its fixed-price forward contract obligations in order to have more freedom to withhold output to increase prices in the short-term wholesale market. Thus, in our view a major challenge to finding appropriate remedies for the competitive effects of such a merger requires finding a package of divestitures that causes the merged firm to maintain a high level of fixed-price forward contracts.

Before proceeding with a discussion of how to apply these methods to determine the competitive impacts of a proposed merger and assess the impact of potential divestiture packages in a bid-based wholesale electricity market, there is one more important feature of electricity supply industries that the analysis must address.

[26]Wolak (2007) demonstrates that forward contracts obligations can commit an expected profit-maximizing supplier to a lower average cost pattern of output within the day, on the order of 5 to 10 percent lower. Therefore, if the firm expects to sell its output at the same price in the forward market or in the short-term market, it may find that signing a fixed-price forward contract that commits it to a lower average cost pattern of daily output is profit-maximizing on an expected value basis.

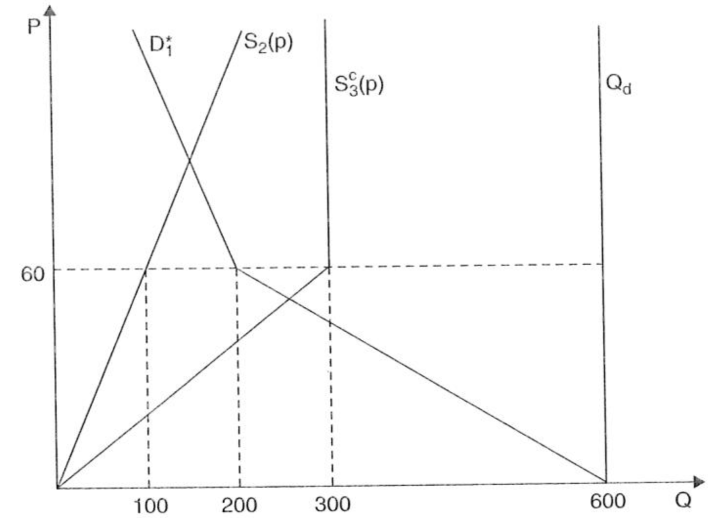
Transmission Constraints and Market Definition

Applying the HMG market definition test, we believe that the relevant product market is straightforward to determine because of the limited ability of consumers to substitute away from electricity. The geographic product market definition is complicated by the fact that the ability of consumers to substitute away from local sources of electricity in favor of more distant sources is limited by the capacity of the transmission network, the operating behavior of other generation units, and the level of demand at other locations in the transmission network. In general, when there is no congestion in the transmission network, the relevant geographic market is the entire PJM Interconnection because any attempt by a local supplier to raise the price at one location or set of locations in the transmission network will be undone by substitution to sources of supply at other locations in PJM. Therefore, during all hours of the year without congestion, the relevant product is wholesale electricity, and the relevant geographic market is the entire PJM Interconnection.

Transmission network constraints can significantly reduce the number of generation units and independent suppliers that are able to serve a location or set of locations in the transmission network. Returning to the three-firm example, suppose that (1) firm 3 is distant from either firm 1 or firm 2, and (2) there is a transmission line with finite capacity between firm 3's location and the location of firms 1 and 2. Figure 1-7 illustrates the impact of this transmission constraint on construction of the residual demand curve facing firm 1, using the same supply curves as in Figure 1-2. The only difference is that a maximum of 300 MWh of firm 3's supply can actually compete against firm 1 and firm 2 because that is the capacity of the transmission interface between firm 3's location and the location of firms 1 and 2. This transmission constraint implies that firm 3's effective supply curve for the purposes of computing firm 1's residual demand curve becomes vertical at a supply of 300 MWh. Figure 1-7 plots the residual demand curve faced by firm 1 with this transmission constraint taken into account. For all output levels, this curve is at least as steep or steeper than the residual demand calculated in Figure 1-3, which does not account for transmission constraints.

This example demonstrates how transmission constraints can reduce the opportunities for consumers to shift to alternative sources of supply and shrink the geographic size of the market. In Figure 1-7, at prices above \$60/MWh (the value where the supply from firm 3 is equal to 300 MWh) firms 1 and 2 no longer face competition from firm 3. In this sense, the transmission network has limited the size of the market in which firms 1 and 2 compete. Therefore, comparing a merger between firms 1 and 2 in a world with infinite transmission capacity between locations in the transmission network with this same merger with finite transmission capacity between locations in the network can yield very different results, depending on the locations of firms 1 and 2 and the location of competitors to these firms. Both the DOJ complaint and the FERC merger authorization decision emphasized that without appropriate mitigation the merger was likely to harm competition in smaller geographic markets in the PJM Interconnection created by transmission congestion.[27]

FIGURE 1-7 Residual Demand of Firm 1 with Transmission Constraints



MERGER ANALYSIS IN BID-BASED WHOLESALE ELECTRICITY MARKETS

This section describes how generation unit willingness-to-supply curves, market prices and quantities, and firm-level fixed-price forward contract obligations can be used to assess the likely competitive impact of a proposed merger.

Returning to the three-firm market example, let us assume that firms 1 and 2 are the merging parties. Following the procedure outlined above, the premerger residual demand curves for firms 1 and 2 are, respectively, the market demand minus the willingness-to-supply curves of firms 2 and 3 and the market demand minus the willingness-to-supply curves of firms 1 and

[27]See p. 10 of the DOJ complaint at http://www.usdoj.gov/atr/cases/f216700/216785.htm and p. 5 of FERC (2005).

3. The residual demand curve of the merged entity is the market demand minus the willingness-to-supply curve of only firm 3.

Figure 1-8 plots the marginal cost curve, MC_2, and D_2, the residual demand curve for firm 2 for the willingness-to-supply curves in Figure 1-2. The best-reply price and quantity pair for firm 2, when it faces residual demand curve D_2, is ($60/MWh, 100 MWh). Figure 1-9 plots the residual demand curve for the merged entity, D_M, and the marginal cost curve for the merged entity, MC_M, which is equal to the horizontal sum of the marginal cost curves of firms 1 and 2. Figure 1-10 computes the intersection of MR_M, the marginal revenue curve of the merged entity, with the marginal cost curve of the merged entity to find the best-reply output and market price for the merged entity with no fixed-price forward contract obligations. This intersection occurs at an output level of 237 MWh for the merged entity, which implies a best-reply price of $72/MWh. Therefore, as a result of the merger, firms 1 and 2 find it unilaterally profit-maximizing to raise prices from $60/MWh to $72/MWh and reduce the amount that they jointly produce from 300 MWh to 237 MWh.

Figure 1-11 performs this same counterfactual merger calculation for D_M, the same value of the residual demand curve for the merged entity as in Figure 1-10, on the assumption that firm 1 has fixed-price forward contract obligations of 100 MWh and that firm 2 has fixed-price forward contract obligations of 50 MWh, so that the merged entity has 150 MWh of fixed-price forward obligations. Figure 1-11 follows the logic presented in Figure 1-6 for computing the best-reply price and quantity with fixed-price

FIGURE 1-8 Best-Reply Price and Quantity for Firm 2

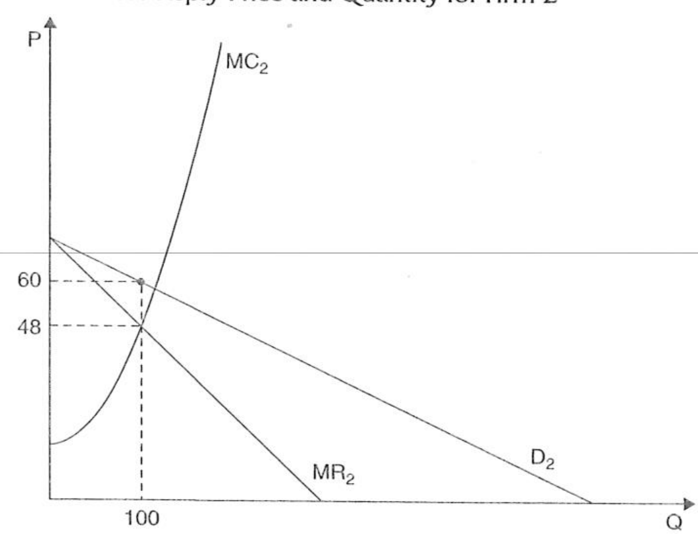


FIGURE 1-9 Marginal Cost Curve and Residual Demand Curve for Merged Firm

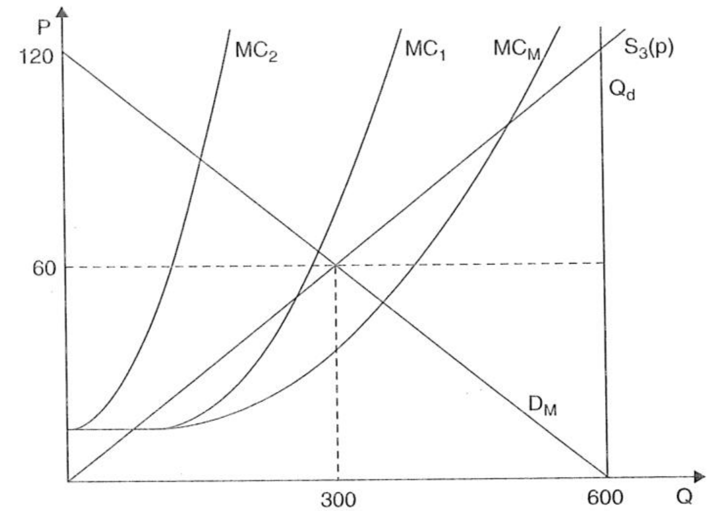


FIGURE 1-10 Calculation of Best-Reply Price and Quantity for Merged Firm with No Fixed-Price Forward Contract Obligations

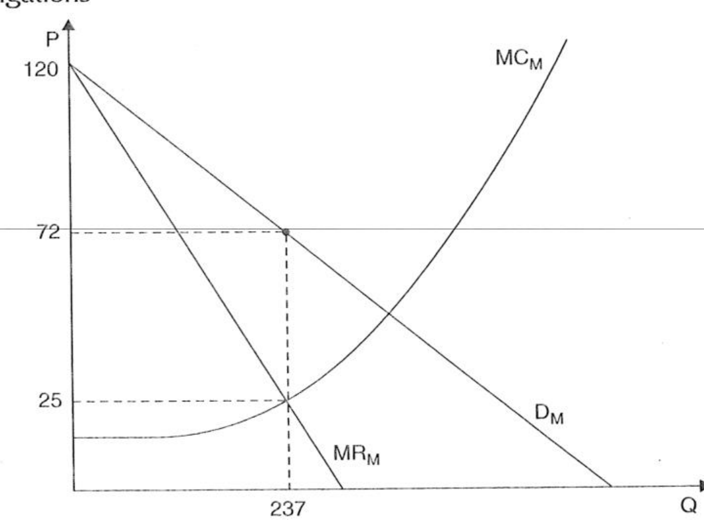
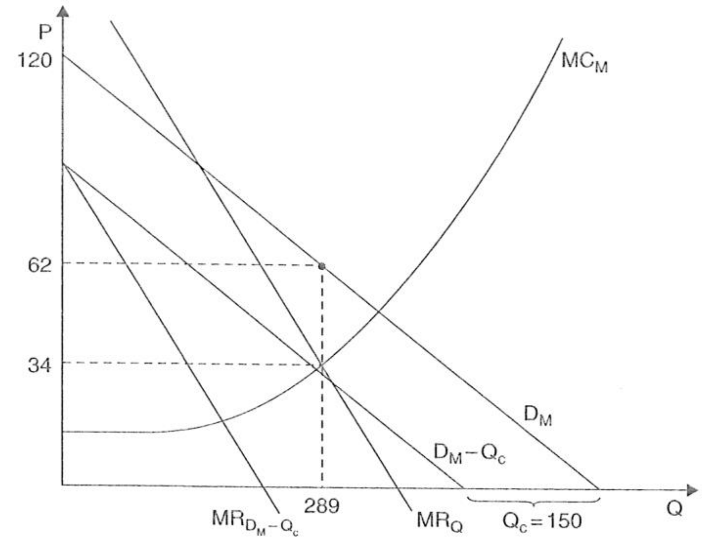


FIGURE 1-11 Calculation of Best-Reply Price and Quantity for Merged Firm with Fixed-Price Forward Contract Obligations



forward contract obligations for the merged entity. The best-reply quantity for the merged entity is 289 MWh, with a corresponding best-reply price of $62/MWh. This price is significantly lower than the postmerger best-reply price without fixed-price forward contract obligations of $72/MWh and very close to the premerger market price of $60/MWh. This result demonstrates a key factor in the merger analysis: For a high enough level of fixed-price forward contract obligations for the merged entity, the competitive impacts of the merger are very small. By this logic, the merger remedy should provide the strongest possible incentives for the combined entity to maintain a high level of fixed-price forward contract obligations relative to its expected output level.

Comparing the residual demand curves of firms 1 and 2 in Figures 1-4 and 1–8 with the residual demand curve of the merged firm in Figure 1-10, two types of differences emerge. First, the merged entity faces a residual demand at every price level that is larger than the residual demand faced by either firm 1 or firm 2. Second, the merged entity's residual demand curve is steeper than the one faced by either firm 1 or firm 2. This implies that the price increase that results from a 1 MWh reduction in output by the merged entity is always greater than the price increase that either firm 1 or firm 2 could bring about by a 1 MWh reduction in its output. Both of these factors imply a greater ability of the merged entity to withhold output to raise

prices in the absence of fixed-price forward contract obligations than was true for either party alone before the merger.

Finding the Appropriate Merger Remedy

We believe that there are two important issues raised by our graphical analysis of the competitive impacts of mergers in bid-based wholesale electricity markets. The first is whether the combination will enhance the ability of the merged entity to cause transmission congestion and therefore limit the amount of competition that its generation units face from other suppliers. The second is what level of fixed-price forward contracts will be chosen by the combined entity after the merger.

Modeling Transmission Congestion

The discussion surrounding Figure 1-7 demonstrates that transmission constraints can increase the steepness of the residual demand curves faced by suppliers. Depending on the capacity of the transmission network that connects locations that are served by the merging parties and their competitors, a merger can substantially increase the ability of either party to segment itself from competition by causing transmission congestion. Because the merging parties each owned a substantial amount of generation capacity in PJM East, which can become electrically separated from the remainder of the PJM Interconnection, the merger could increase the frequency and duration of transmission congestion that reduces the amount of competition faced by the merged entity.

When there is transmission congestion between PJM West, where there are many low-variable-cost generation units, and PJM East, where the PECO and PSEG service territories are located, the relevant geographic market for the merger analysis is PJM East. During these hours, suppliers located in PJM West are unable to limit the ability of suppliers in PJM East to raise wholesale prices because transmission constraints prevent any more electricity produced in PJM West from being consumed in the PJM East region.

To assess whether the merger would have increased the opportunities for the combined entity to segment the market, the combined firm's residual demand curve can be computed under the assumption of transmission congestion that eliminates the ability of certain generation units to compete against it. In this case the residual demand curve that the merged entity faces excludes all generation units owned by nonmerging parties that are located on the other side of a congested transmission interface. For the proposed PSEG and Exelon merger, this requires excluding all suppliers located outside of PJM East from the merged entity's residual demand curve during hours when there is congestion into PJM East. This reduces the price elasticity of the residual demand curve faced by the merged entity during congested hours, which results in higher estimated postmerger prices.[28]

Postmerger Forward Contracting Decisions

The graphical analysis described above demonstrates that the *incentive* to exercise unilateral market power by a firm with a substantial *ability* to raise prices can be significantly limited or even eliminated by an appropriate choice of the level of its fixed-price forward contract obligations. A state or federal regulator or antitrust authority is likely to find it impossible to set the quantity of fixed-price forward contract obligations that the merged entity must hold into the indefinite future. Consequently, if these agencies would like the combined entity to maintain a high level of fixed-price forward contract obligations relative to its expected output levels, then a precondition for the merger must be sufficient divestitures of generation capacity to ensure that the merged entity will find it unilaterally profit-maximizing to sign sufficient fixed-price forward contracts into the indefinite future to limit its incentive to exercise unilateral market power in the short-term wholesale market.

State public utility commissions can also mandate (or at least provide very strong financial incentives) for retailers subject to their jurisdiction to maintain high levels of fixed-price forward contracts (relative to their final demand obligations) signed far in advance of the delivery date. In this case, the Pennsylvania Public Utilities Commission's requirement that PECO, which is owned by Exelon, freeze retail rates until 2010 accomplished that goal. However, we believe that if the wholesale competition concerns associated with the merger were not addressed, retailers purchasing far in advance of delivery may have needed to pay higher prices for these forward

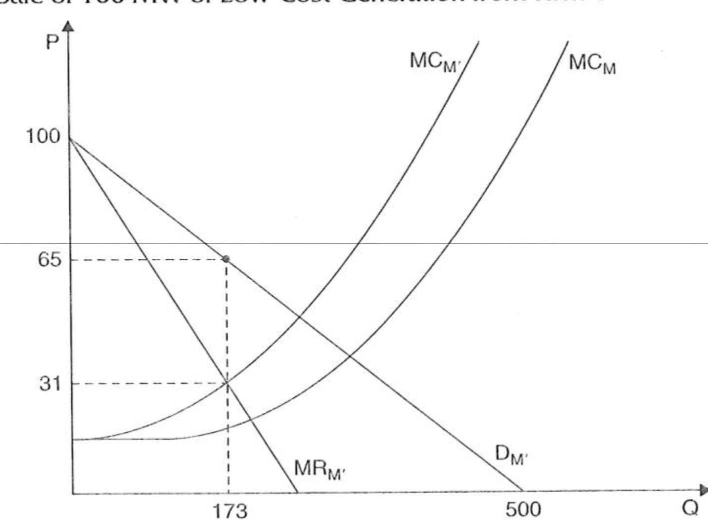
[28]PECO and PSEG each owned transmission assets in the PJM East region, so the merger would also have increased the concentration of transmission facility ownership in PJM East. However, we believe that this was unlikely to enhance the ability of the combined entity to use these transmission assets to cause congestion between PJM West and PJM East. Both before and after the merger, the PJM Interconnection would allocate the use of these transmission facilities to the generation units based on their willingness to supply energy. The PJM Interconnection market rules requiring equal access to all transmission facilities in the PJM region imply that the combined entity after the merger, or PECO and PSEG before the merger, could not deny any market participant access to these facilities. Nevertheless, it is possible that the combined entity could increase the frequency of PJM East's becoming a separate market by increasing the frequency and duration of transmission outages. This strategy was very unlikely to be profitable because the merged firm would also own a substantial amount of low-variable-cost generation outside of PJM East that it would like to use to serve its load obligations in PJM East. Page 18 of the merger announcement presentation (http://media.corporate-ir.net/media_files/irol/12/124298/pdfs/EXC_PSEG_AnalystPres_122004.pdf) contains a figure with the estimated variable cost in 2006 for all PSEG and Exelon generation units in PJM. It is also likely that the PJM Interconnection would be able to detect and penalize a significant increase in the frequency and duration of transmission outages on the links between PJM West and PJM East. Consequently, we believe that it was unlikely that the increased concentration in transmission ownership would have affected the extent of unilateral market power exercised by the combined entity in the wholesale electricity market.

contracts because the merged entity controlled such a large fraction of existing generation capacity. Divestitures of generation capacity from the merged entity may be necessary to ensure that it is unable to raise prices in the market for long-term contracts.

The residual demand analysis framework can be easily adapted to address the impact of generation unit divestitures on wholesale prices. To study the effect of the divestiture of a specific generation unit or set of generation units, Figure 1-12 plots the residual demand curve of the merged entity under the assumption that 100 MW of low-cost generation is divested by the merged entity. To simplify the analysis, we assume that this 100 MW is inelastically supplied by the new owner, which effectively shifts inward the residual demand faced by the merged entity by 100 MWh. This postdivestiture residual demand curve is denoted by $D_{M'}$ and the postdivestiture marginal cost curve of the merged entity is denoted by $MC_{M'}$. The postdivestiture best-reply price for the merged entity with no fixed-price forward contract obligations is \$65/MWh. This is significantly less than the best-reply price for the merged entity with no fixed-price forward contracts of \$72/MWh in Figure 1-10. Different divestiture packages affect both the residual demand curve faced by the merged entity and its marginal cost curve.

Because the merged entity faces a more price-elastic residual demand curve postdivestiture at every level of output, it will have a lesser ability to raise prices through its unilateral actions. This greater elasticity of the residual demand curve implies a greater willingness to sign a given quantity of fixed-price forward contracts because the supplier gives up fewer

FIGURE 1-12 Postdivestiture Best-Reply Price and Quantity for Sale of 100 MW of Low-Cost Generation from Firm 1

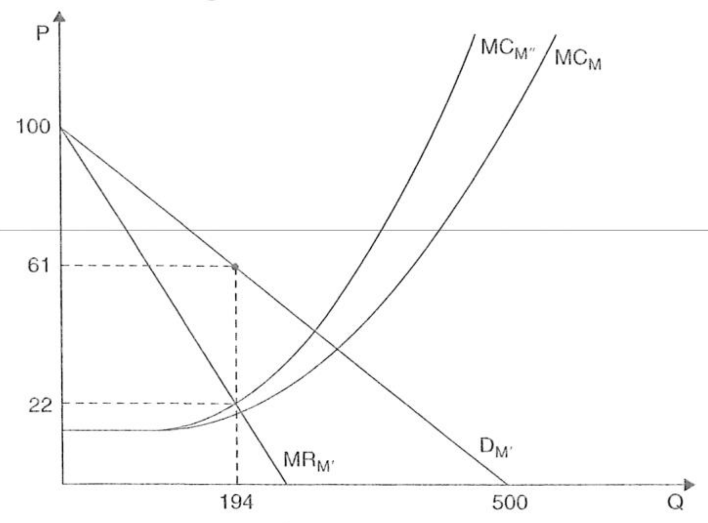


opportunities to exercise unilateral market power in the short-term market by signing these contracts. In addition, as a comparison of Figure 1-4 with Figure 1-6 demonstrates, by signing these fixed-price forward contract obligations the supplier precommits to a higher level of output than it would without these obligations.

According to the logic of our model framework, the process of finding the best possible divestiture package must balance a number of competing concerns. First, the merging parties must be willing to accept the divestiture package. Second, the divestiture package should not increase the geographic concentration of generation ownership, or else the merged entity will have greater opportunities to segment the market by causing transmission congestion. Third, the form of the aggregate marginal cost curve of the merged entity affects its incentive to exercise unilateral market power and its incentive to sign fixed-price forward contracts. This marginal cost curve can be altered by divesting various combinations of generation units from the assets owned by the two parties.

To understand this last point, consider the following stark, but relevant, example: Suppose that the 100 MW of divested generation capacity came from the high-variable-cost generation units owned by firm 2. The marginal cost curves in Figure 1-9 show that firm 1 has almost 150 MW of very low-marginal-cost units, whereas firm 2 has less than 10 MW. Figure 1-13 plots the postdivestiture average marginal cost for the merged entity, assuming that 100 MW of divestitures comes from the high-variable-cost units owned by firm 2 instead of the low-variable-cost units owned by firm 1, as is the case in Figure 1-12. For consistency with Figure 1-12, this 100 MW of

FIGURE 1-13 Postdivestiture Best-Reply Price and Quantity for Sale of High-Cost Generation from Firm 2



divested capacity is assumed to be inelastically supplied by the new owner, so the residual demand curve faced by the merged entity is the same as in Figure 1-12. The intersection of postdivestiture marginal cost function $MC_{M''}$ with the marginal revenue curve associated with the postdivestiture residual demand curve yields a best-reply price of $61/MWh, which is lower than the best-reply price in Figure 1-12. This analysis illustrates the importance of properly choosing where in the merged entity's marginal cost curve to divest generation capacity in order to limit the adverse impacts of a proposed merger.

This example is relevant to the PSEG and Exelon merger because firm 1 can be thought of as Exelon, and the low-variable-cost units are its nuclear generation facilities. Firm 2 can be thought of as PSEG because it owns a much smaller amount of nuclear MW, as well as a significant amount of higher-variable-cost natural gas-fired generation units. In this example, for the same total MW of generation capacity divested and the same residual demand curve of the merged entity, selling off only high-marginal-cost units reduces the adverse price effects by more than does selling off the same total MWs of capacity of low-marginal-cost units.

This logic also leads to differences in the incentives for the postdivestiture merged entity to enter into fixed-price forward contract obligations. By leaving the merged entity with only low-marginal-cost units, the incentive of the firm to sign fixed-price forward contracts is much higher because the firm knows that it has significantly fewer profitable opportunities to exercise unilateral market power in the short-term market and may face a sustained period of market-clearing prices below its average cost. Conversely, if the merged entity is left with a significant amount of high-marginal-cost units, it will have less of an incentive to sign fixed-price forward contracts because it knows that it is giving up many more opportunities to exercise unilateral market power in the short-term market.

THE PSEG-EXELON MERGER ANALYSIS

This section first describes the initial divestiture proposal made by the parties to address the competition concerns associated with the proposed combination. It then discusses the results of the various merger reviews and the preconditions agreed to by the merging parties and reviewing agencies: the FERC, the Pennsylvania Public Utility Commission, the DOJ, and the NJBPU. This section concludes with our analysis of why the parties eventually decided not to move forward with the merger.

Initial Merger Proposal

In their initial submission to the FERC, the merging parties acknowledged potential competition problems for the PJM Interconnection and PJM East geographic markets. The FERC (2005, p. 7) notes that, depending on how the Herfindahl-Hirschman Indexes (HHIs) are computed, postmerger HHIs in PJM East ranged from 2057 to 2492, and merger-related changes in HHIs ranged from 848 to 1067, which is well above what would be considered cause for concern in a highly concentrated market. With the initial FERC merger application, the companies proposed to divest a total of 2900 MW of generation capacity, subject to minimums on characteristics of the units sold: approximately 1000 MW of peaking capacity and 1900 MW of mid-merit capacity, with at least 550 MW that was coal-fired.[29] The combined entity proposed to complete this sale as soon as possible: within eighteen months of the close of the merger.

The parties also proposed a "virtual divestiture" of 2600 MW base-load nuclear generation units, which included 2400 MW in PJM East. This virtual divestiture would take one of two forms: (1) fixed-price long-term contracts for at least fifteen years or the life of the generation unit or (2) an annual auction in twenty-five MW blocks of three-year firm entitlements at fixed prices to the output of the nuclear generation units. This virtual divestiture was designed by the merging parties to limit the incentive of the combined entity to increase prices in the short-term market without losing the benefits that were associated with applying Exelon's nuclear generation plant operating expertise to all of the nuclear facilities owned by the combined entity.[30]

The state regulatory filings by the parties addressed the state-level public benefits requirements associated with the merger. In these filings, the merging parties emphasized that the merger would enhance the ability of individual companies to provide cost-effective, safe, and reliable service without any price increases to the retail customers of PECO, ComEd, and PSEG. These filings emphasized the existence of operating cost savings from the merger associated with scale, scope, and best-practice sharing, without much detail as to the sources of these benefits except for the discussion of Exelon's nuclear plant operation expertise's being applied to PSEG's facilities. The filings also noted that the combination would result in a reduction of the combined entity's workforce of approximately 5 percent and that, to the maximum extent possible, these workforce reductions would occur through attrition, although severance programs could also be utilized.[31]

[29]Generation capacity is often characterized by when during the day a unit is expected to operate. Base-load units typically operate during all hours of the day. Mid-merit or intermediate units operate during the vast majority of hours of the day. Peaking capacity operates only during the highest demand (peak) hours of the day.

[30]See "PSEG Defends Merger, Argues Divestiture and PJM Would Prevent Market Manipulation," *Power Markets Week*, December 15, 2005, p. 10, for a discussion of Exelon's rationale for the virtual divestiture.

[31]Page 25 of the merger announcement presentation (http://media.corporate-ir.net/media_files/irol/12/124298/pdfs/EXC_PSEG_AnalystPres_122004.pdf) discusses these sources of cost savings from the merger.

The parties claimed annual pretax merger synergies in the first year of $400 million, with this number increasing to $500 million for the second year. Approximately 86 percent would come from operating cost savings from eliminating redundant activities at the two companies and realizing economies of scale in the acquisition of inputs. According to the joint proxy statement and prospectus for the 2005 annual meeting of Exelon shareholders, the remaining 14 percent would come from increased capacity utilization at PSEG's nuclear facilities.[32] This joint proxy statement estimated the cost to achieve these synergies to be $450 million in the first year following the completion of the merger and approximately $700 million over the four years following the merger.

Based on these figures, the joint proxy statement estimated the net benefits of the merger to be about $200 million, which did not leave a substantial amount of merger benefits to share with consumers in Pennsylvania and New Jersey to meet the state-level public benefit test for merger approval in both states—an issue very relevant to the final outcome of the proposed merger. We believe that the prospect that the nuclear operating cost savings and increased efficiency for PSEG's nuclear facilities would be realized without the proposed acquisition (because of the separate nuclear operating agreement between Exelon and PSEG noted earlier) is likely to have further reduced the benefits that the parties directly attributed to the merger. The fact that the parties had almost two years of experience with the joint operating agreement at the time that the negotiations with the NJBPU broke down is also likely to have reduced their desire to share the nuclear plant operating cost savings and revenue increases with consumers in New Jersey.

The state-level filings also emphasized that PECO, ComEd, and PSEG would remain as separate corporations after the merger with headquarters in Philadelphia, Chicago, and Newark, respectively. Finally, the filings emphasized that local charitable contributions and support for economic development within each state would continue at the same or higher levels after the merger.

The Merger Approval Process and Modifications of Divestiture Packages

The FERC merger review process identified several conceptual and factual errors in the initial analyses filed by the merging parties to justify their initial divestiture packages.[33] A number of parties also disputed proposals by the merging parties to restrict the set of potential buyers of the divested

[32]"Joint Proxy Statement and Prospectus for the 2005 Annual Meetings of Shareholders, Including Action on the Proposed Merger of PSEG and Exelon," p. 96 (http://www.exeloncorp.com/corporate/investor/proxy_statements/2005/proxy_2005.pdf).

[33]FERC (2005), pp. 23–24.

assets to entities without large preexisting market shares in the PJM nterconnection. In order to respond to these complaints and in order to relax the restrictions on the preexisting market shares of potential buyers of the divested assets, in May 2005 the merging parties upped the initial 2900 MW divestiture proposal to 4000 MW, composed of roughly 700 MW of base-load units, 2100 MW of mid-merit units, and 1200 MW of peaking units.[34] On July 1, 2005, the FERC approved the merger with this divestiture package and the 2600 MW virtual divestiture of nuclear capacity described above.

The next to act was the Pennsylvania Public Utility Commission, which approved the merger with the proposed divestiture package in late January 2006. As part of the merger agreement, PECO agreed not to increase retail prices until 2010. It also agreed to increase the amount of energy usage per household that could qualify for a reduced price of electricity and to spend $1.2 million on additional consumer outreach to acquaint low-income consumers with this program. PECO also pledged to maintain its corporate headquarters in Philadelphia through at least 2010. Subject to these terms and conditions, the Pennsylvania Public Utility Commission found that the parties had met the public interest standard for approval of the merger.

From the early summer of 2005 until June 2006, the DOJ undertook a comprehensive analysis of the merger.[35] In late June 2006 the DOJ reached a settlement with the merging parties that involved the divestiture of 5600 MW of fossil-fuel generation capacity. This settlement specified the divestiture of all of the units at six generation facilities in the PECO and PSE&G service territories. All of the facilities in this divestiture package had variable costs that were close to the average market clearing price in PJM during a number of hours of the day during the sample period, which is consistent with the pattern of divestiture recommended by the logic in Figures 1-12 and 1-13: For a given MW quantity of generation divestitures, selling units with variable costs in the range of actual market clearing prices is likely to result in lower postdivestiture prices than is selling the same amount of capacity in low-variable cost units.[36]

It is also important to note that the plant divestitures required by the DOJ would have resulted in the merged entity's owning less fossil fuel-generation capacity in the PJM East region than PSEG owned before the merger, which is consistent with the DOJ's desire to address the PJM East competition issues noted in its complaint. Under the terms of the DOJ

[34]The details of this supplemental filing with FERC are described in the May 10, 2005, PSEG press release (http://www.pseg.com/media_center/pressreleases/articles/2005/2005-05-10.jsp).

[35]A discussion of the DOJ's analysis of the merger and its eventual settlement can be found in Armington, Emch, and Heyer (2006).

[36]Page 18 of the merger announcement presentation (http://media.corporate-ir.net/media_files/irol/12/124298/pdfs/EXC_PSEG_AnalystPres_122004.pdf) shows the estimated variable cost in 2006 for all PSEG and Exelon generation units in PJM.

agreement, the merged entity would have had to enter into an agreement to sell this capacity within 150 days after the merger closed. In addition, for a period of ten years following the merger, the combined company would have had to obtain the DOJ's prior approval before acquiring or obtaining control of power plants in the PJM East region.

No nuclear generation capacity was required to be included in the DOJ's divestiture package. This is consistent with the analysis in Figures 1-12 and 1-13 described above. An expert witness for the merging parties argued that the combined entity would not withhold nuclear capacity to raise wholesale prices because the extremely low variable cost of this capacity relative to the typical market price in the PJM Interconnection makes withholding output from these units very costly.[37] As noted earlier, a major source of benefits claimed by the parties from the proposed merger would be the increased efficiency at PSEG's nuclear facilities to be realized by implementing Exelon's management practices, and the incentive to realize these operating cost savings and revenue increases would be greater if Exelon owned rather than simply operated PSEG's nuclear assets for a finite period of time, which would be the case for any of the virtual divestiture packages. This logic and the analysis in Figures 1-12 and 1-13 suggest that the DOJ was wise to focus its efforts on fossil fuel units with variable costs at or near average hourly prices in PJM.

The only outstanding merger review process at this point was that by NJBPU, the New Jersey public utility regulatory body. The NJBPU issued an order on June 20, 2005, requiring Exelon and PSEG to prove that PSE&G customers and the state of New Jersey would benefit from the merger and that the merger would not lead to adverse effects on competition, employees of PSE&G, and the reliability of electricity supply to the state. Negotiations between the merging parties and the NJBPU proceeded for almost three months after the agreement with the DOJ was announced. In its Form 10-Q to the Securities and Exchange Commission for the quarter ending June 30, 2006, PSEG noted that the merging parties recently had made a materially enhanced cash settlement offer to the NJBPU, which they believed would provide substantial positive benefits to customers and to the state of New Jersey.[38] This cash settlement offer could have been used for a variety of customer and state benefits, primarily price reductions for PSE&G's customers. The Form 10-Q report noted that PSE&G's earnings and cash flow would be materially reduced in the near term as a result of this settlement offer. In this document, PSEG also expressed the hope that a settlement with the NJBPU could occur in time to allow the merger to close by the end of the third quarter of 2006.

[37]See "PSEG Defends Merger, Argues Divestiture and PJM Would Prevent Market Manipulation," *Power Markets Week*, December 15, 2005, p. 10, for a discussion of this point.

[38]This document is available at http://yahoo.brand.edgar-online.com/EFX_dll/EDGARpro

In mid-September 2006 PSEG and Exelon announced that Exelon had given PSEG formal notice of the termination of the merger agreement. At the same time, the parties withdrew their application for approval of the merger at the NJBPU, which had been pending for more than nineteen months. Although neither party made any statements about the specific reasons for the termination of the merger, the major points of difference were the magnitude of benefits that New Jersey ratepayers could expect to see from the merger and how the wholesale market competitive effects associated with the combination would be addressed. Based on the public disclosures by PSEG in its Form 10-Q report, it seems likely that the amount of the public benefits settlement desired by the NJBPU may have been sufficiently large relative to the other concessions to which the merging parties had agreed with the other reviewing agencies to cause the net benefits that PSEG and Exelon expected to realize from the merger to be very close to zero or even negative. The estimated merger net benefits of $200 million referred to earlier provide further credibility to this explanation for the termination of the merger agreement.

LESSONS FOR PARTICIPANTS IN FUTURE MERGERS IN WHOLESALE ELECTRICITY MARKETS

The quantitative methods presented here can be applied to a merger in any bid-based wholesale electricity market. As the number of these electricity markets in the United States increases, the opportunities to apply these methods are likely to increase. These methods allow a detailed quantitative assessment of the competitive impacts of proposed packages of generation unit divestitures that would address the incentives for the merged entity to maintain a high level of fixed-price forward contract obligations following the merger and limit the opportunities for the merged entity to segment a larger geographic market from the remainder of that market in order to raise the wholesale prices paid to its generation units.

The ultimate outcome of this proposed merger suggests that few mergers involving generation unit owners in wholesale electricity markets will be able to survive the multistage, federal and state antitrust and regulatory approval process and still provide value to the shareholders of the merged companies. The public benefit standard applied by most public utility commissions provides state governments with a substantial ability to extract financial concessions from the merging parties that may cause the merging parties to terminate potentially beneficial mergers.

It is unclear whether the proposed merger was an example of this phenomenon. The description of the merger demonstrates that it was difficult to find tangible and sizeable benefits that could be solely attributed to the merger. However, it is an open question whether the merger was in the broad public interest in the sense that it benefited all consumers served by

the PJM Interconnection, and the merger was terminated because the New Jersey and Pennsylvania public utility commissions demanded too many explicit financial concessions for ratepayers and citizens. Exelon's upper management appears to have felt that this was the case.[39] In late May 2006, before the DOJ settlement was announced, a major investor in Exelon, the hedge fund Duquesne Capital, asked the board of directors of Exelon to terminate the merger agreement, stating that it was "a deal which has gone very bad with the passage of time."[40]

The public benefit criteria for merger analysis traditionally used for mergers involving public utilities within the boundaries of states may therefore be inappropriate in those instances when the merging utilities participate in multistate wholesale markets such as PJM. This local public benefit view of mergers of electric utilities involved in multistate wholesale markets may need to be revised before these sorts of mergers can be approved.

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[39] See "NJBPU Staff's Demand for Shared Savings Is Biggest Obstacle to Exelon/PSEG Merger," *Electric Utility Week*, June 5, 2006, p. 4, for a statement by Exelon upper management concerning the major obstacles to completing the merger at that time.

[40] See "Duquesne Capital Asks Exelon to Walk Away from PSEG Merger, Now a 'Very Bad' Deal," *Electric Utility Week*, May 22, 2006, p. 15.

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CASE 2

Oracle's Acquisition of PeopleSoft: *U.S.* v. *Oracle* (2004)

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INTRODUCTION

On June 6, 2003, the Oracle Corporation made an unsolicited cash tender offer for all of the outstanding shares of PeopleSoft, Inc. Oracle and PeopleSoft are enterprise software companies that develop, manufacture, market, distribute, and service software products that are designed to help businesses manage their operations. Together with SAP AG, they are the three largest companies in the industry. Oracle's total revenues in fiscal year 2004 were $10.1 billion, while PeopleSoft and SAP AG had total revenues in 2003 of $2.3 billion and $8.0 billion, respectively. As discussed in detail below, all three firms produce enterprise resource planning (ERP) software that enables companies to operate their human resources, finances, supply chains, and customer relations.

In February 2004, the U.S. Department of Justice (DOJ), together with the states of Connecticut, Hawaii, Maryland, Massachusetts, Michigan, Minnesota, New York, North Dakota, Ohio, and Texas (plaintiffs) filed suit

*Preston McAfee served as an economic expert on behalf of the U.S. Department of Justice, Antitrust Division, in the matter of *U.S. et al.* v. *Oracle*. Michael Williams and the ERS Group were retained by the U.S. Department of Justice's Antitrust Division to assist in the development of the economic analysis underlying McAfee's testimony. During this period, David Sibley was deputy assistant attorney general for economics at the Antitrust Division.

The Antitrust Revolution

Economics, Competition, and Policy

Fifth Edition

Edited by

John E. Kwoka, Jr.
Lawrence J. White

New York Oxford
OXFORD UNIVERSITY PRESS
2009