Synapse
Energy Economics, Inc.

An RPM Case Study:

Higher Costs for Consumers, Windfall Profits for Exelon

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I. Executive Summary

In this report, we study the capacity revenues of nuclear generating facilities operated by Exelon Generation in northern Illinois under PJM Interconnection LLC's (PJM's) proposed capacity market design. This market design has been referred to as the Reliability Pricing Model (RPM). Specifically, we find that:

- Under RPM, capacity prices will be determined by an administrative process which is intended to produce prices higher than the current market price for capacity.
- These prices represent a huge wealth transfer from ratepayers to owners of existing generation, with no guarantee that new capacity will be built.
- At the target RPM price, Exelon's nuclear plants in northern Illinois stand to gain almost $390 million in additional capacity revenues, compared to the 2004 capacity market price, at ratepayers' expense. At the maximum RPM price, these plants would receive a $1.2 billion increase in capacity revenues.
- At the RPM target price, total capacity payments would increase by over $5 billion, representing a 25% increase in the price of wholesale power.

II. Introduction

PJM is the Regional Transmission Organization (RTO) that runs the transmission grid serving 45 million people across parts of 13 states stretching from the east coast to Chicago. In addition to being responsible for regional reliability and the determination of which power plants run at any given time, PJM operates the wholesale electricity markets. PJM is governed by a board of directors operating with the advice of its staff and 350 stakeholder PJM members (including the Citizens Utility Board, ComEd, power generators, and industrial representatives from Illinois).

The staff of PJM has concluded that current market prices are insufficient to promote the construction of new generation capacity and believes that a threat to reliability may be looming, despite the fact that the region is presently awash in capacity. In response to this alleged problem, PJM staff, supported by generators such as Exelon and Midwest Generation, has proposed the Reliability Pricing Model (RPM)[1].

[1] This paper analyzes the cost impact of RPM based on analyses done by PJM over the last year. On August 31, 2005, PJM filed for acceptance of its RPM approach with FERC and included a new demand curve that has a slightly different shape than the draft version used in this analysis. The shape of the new demand curve may change the cost impacts in the first few years of RPM implementation. However, the expected "target" cost impacts which are the focus of this analysis, are not significantly altered by the revised demand curve. This is because the proxy

The goal of RPM is to apply an administrative process to produce a price for capacity which is significantly higher than the price which the current market would produce. This price would then be paid—on a per-MW capacity basis—to all generating resources in the affected area. Because most resources in all parts of PJM are already in place and already profitable, most of these administrative payments would be made to generators which have no need for these additional revenues to satisfy their capital requirement. However, PJM claims that putting these payments in place would provide sufficient incentive for new generation investments where they are needed and support some existing generation that is only marginally profitable today. While this hope may or may not be realistic, RPM would unquestionably produce higher electricity prices for consumers, windfall profits to existing generation owners, and a strong, perverse incentive for these owners to make sure that capacity remains in short supply.

This paper provides an analysis of the revenues that one existing resource owner, Exelon Generating Company, might expect to receive in capacity payments under RPM for its nuclear facilities in Illinois[2]. While the specific level of future capacity payments under any system is unknown, we use market data and historical and forecasted capacity prices in PJM to illustrate possible future scenarios. For perspective, we use historic market data to estimate the revenues these resources are receiving today from the current energy and capacity markets.

We find that Exelon's nuclear fleet, which has already had its capital costs substantially funded by ratepayers and remains quite profitable in the energy market, stands to receive up to $1.2 billion in additional revenue every year, at ratepayer expense, under the RPM. This stream of revenue depends strongly on scarcity of capacity, and we demonstrate that Exelon stands to make hundreds of millions of dollars *more* as long as investment in new generation is limited. This evidence demonstrates that while RPM would be extremely costly for consumers, it is neither a reasonable nor cost-effective way to promote investment in new generation. In fact, there is little reason to believe that it would be effective at all.

III. Background

The efforts to develop a new mechanism for ensuring long-term resource adequacy have preoccupied the three Northeast ISOs for the last several years.[3] Most recently, all three ISOs have proposed modifications to their capacity pricing systems

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peaker cost estimates and ancillary service revenues adjustment used in PJM's August filing, which are the basis of the target capacity price under RPM, are consistent with the earlier draft proposals.

[2] Synapse has done an analogous study in June 2005 for the Pennsylvania Office of Consumer Advocate which analyzed the potential capacity revenues under RPM for four large base load plants in Pennsylvania (two nuclear and two coal plants). The report on that study is available on Synapse's website www.synapse-energy.com.

[3] NY, NE and PJM; although NE and PJM are RTOs, they all perform very similar regional functions.

implementing a "demand curve" to establish an administrative clearing price for all resources within specific zones. In PJM, this mechanism is referred to as the Reliability Pricing Model (RPM). As with the other ISO proposals[4], much attention has been focused on the expected impact of this approach on capacity prices. It is the intention of each of these demand curve approaches that capacity prices, and capacity revenues for all resources, rise significantly above historical and current market prices.

PJM claims that RPM will address local capacity shortfalls by providing incentive for investment in new generation in capacity-short sub regions. It has also been suggested that the new capacity revenues will provide needed revenue to "at risk" generation in such areas, delaying or deferring their retirements and preserving needed capacity. While local capacity shortfalls represent a significant and legitimate reliability concern in PJM, it is not clear that the greatest obstacle to investment is insufficient financial incentive for developers. Availability and control of sites, insufficient transmission infrastructure and local opposition to new power plants are at least as important obstacles, and often more so. Under the proposals made available by PJM thus far, RPM would increase capacity prices not only in these locations but throughout the system, without resolving any of these other issues.

Even if the RPM mechanism were to succeed in attracting new generation where it is needed, most of the considerable transfer of ratepayer resources would go to owners of existing generating units, not to developers of new capacity. In many cases, as with Exelon's nuclear fleet, the capacity being subsidized in this manner was already substantially funded by consumers through the traditional ratemaking process. In addition, these generation owners have been further compensated through transition charge payments, and they are receiving generous compensation through energy, capacity, and/or ancillary services markets. If these high, externally imposed capacity payments failed to attract new generation, the payments to owners of existing and profitable units would hold steady or increase as the capacity shortfall worsened. Once in place, these capacity payments will provide a significant source of revenue for existing generation, at ratepayer expense, which may continue for years or decades into the future.

In sum, the RPM approach represents a certain stream of large payments to existing generators as long as the capacity shortage persists, the untested promise of smaller, short-term payments to developers of new capacity, and an enormous expense for ratepayers. Whether or not it would effectively resolve resource adequacy concerns is unknown, but there would clearly be a significant incentive for owners of existing generation, such as Exelon, to ensure that it did not.

[4] For an overview of the three ISO proposals, see *Capacity for the Future: Kinky Curves and Other Reliability Options,* Synapse December 2004.

IV. The Exelon Nuclear Fleet

Exelon has six nuclear generating stations in northern Illinois with a total of eleven operating reactors, not including the Zion station which is permanently shut down (Table 1). All except the Quad Cities plant are 100% owned by Exelon; Quad Cities is 75% owned by Exelon. The combined capacity of the Exelon-owned nuclear fleet in northern Illinois is 10,978 MW, operating with a weighted average capacity factor of 95%. Combined, these plants represent about 2/3 of Exelon's portfolio of owned or contracted generating capacity in Illinois, and more than enough capacity to supply Exelon's annual energy obligation to ComEd.

Table 1: Exelon's Nuclear Generating fleet in Illinois

Unit	Exelon Share	Reactors	Total Capacity	2003 Capacity Factor
Braidwood Generating Station	100%	2	2,362	97%
Byron Generating Station	100%	2	2,356	97%
Clinton Power Station	100%	1	1,017	97%
Dresden Generating Station	100%	2	1,700	92%
LaSalle County Generating Station	100%	2	2,260	93%
Quad Cities Generating Station	75%	2	1,710	92%
Zion Generating Station	*Out of Service*		-	
			10,978	95%

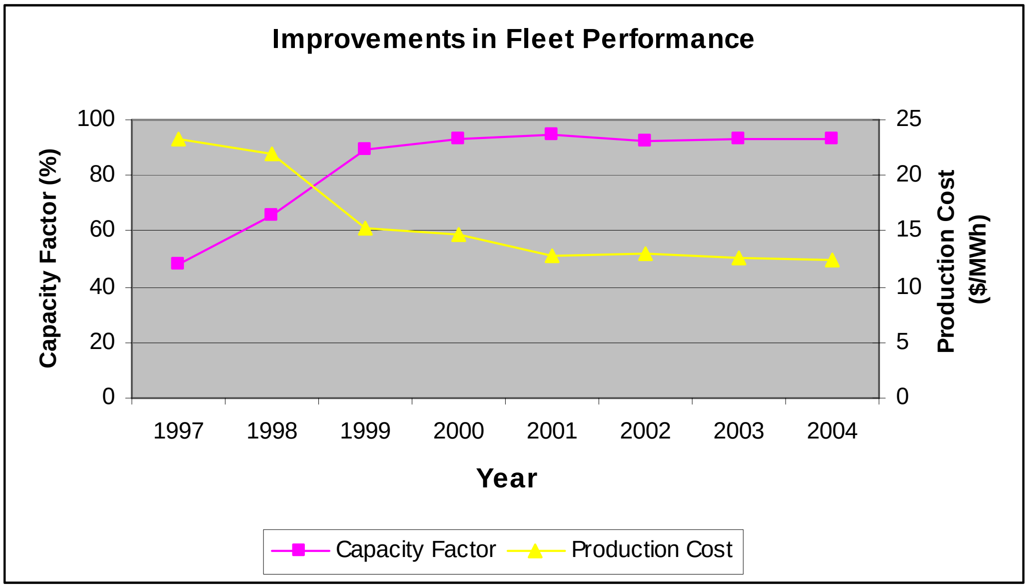
Source: *http://www.eia.doe.gov/cneaf/nuclear/page/at_a_glance/reactors/nuke1.html*

Roughly coincident with deregulation of the wholesale market in Illinois, ComEd and Exelon have achieved performance improvements to the nuclear fleet resulting in a significant increase in capacity factor and a concomitant decrease in production cost (Figure 1). This improvement in performance has demonstrated that these plants have much greater value as commercial assets than was apparent under the regulated market. At the same time, a dramatic increase in the price of fossil fuels has driven up the price of electricity and boosted the value of the output of Exelon's plants[5]. As a result, all of Exelon's nuclear resources are currently earning much higher revenues in the energy market than would have been anticipated during market restructuring, calculation of transition charges and the spin-off of these assets by ComEd. In addition, assuming recent Northern Illinois capacity prices are an indication[6], Exelon is receiving over $100 million annually in capacity payments for these units today.

[5] Under a clearing price auction, all resources are paid the highest accepted offer (the marginal unit price) each hour. During most hours the marginal unit is a gas resource, so most other-fueled resources (such as nuclear and coal) earn excess revenues in each hour above their short run marginal costs. As natural gas prices rise, so do these excess revenues.

[6] Because much of the current capacity market is transacted through long-term bilateral contracts, and in particular between Exelon and ComEd during Exelon's formation, it is impossible to know exactly how much money Exelon is being paid for the capacity value of their resources.

Figure 1



Average capacity factors and performance costs for Exelon nuclear fleet. (Source: Testimony of Christopher Crane, Senior Vice President of Exelon in support of merger with PSEG, Docket # EC05-43-000.)

V. Revenues

Current market revenues

It is impossible to know specifically what Exelon is earning from the output of its nuclear plants because the output is purchased by ComEd under bilateral contracts covering multiple resources[7]. However, under a market system the terms of such contracts should reflect the expectation of market prices. We can calculate the *value* of the output of these plants by using historical price data for the Northern Illinois hub, which are readily available for the period starting May 2004 when the ComEd region began reporting prices through PJM[8]. We estimate energy revenues for one complete year, from July 2004 through June 2005 by multiplying the average of these prices by the availability-adjusted capacity of Exelon's units. Because all of the units have high capacity factors (averaging 95%) it is reasonable for our current purposes to assume that they were equally available during off-peak and on-peak periods, as long as we properly adjust for unavailability by de-rating the units by their capacity factors for all hours. For example, a unit with 1000 MW capacity and

[7] ComEd's existing Power Purchase Agreement with Exelon is for a full-requirements product. Without access to all of the contractual arrangements that Exelon Generation has with intermediate and peak load generators it is impossible to determine precisely the earnings of Exelon Generation's nuclear plants.
[8] PJM energy price data is available at http://www.pjm.com/markets/energy-market/real-time.html

a 95% capacity factor would be assumed to run for all hours with an output of 950 MW.

To calculate recent capacity revenues, we used the capacity prices reported in the 2004 PJM State of the Market report[9]. Because ComEd had a separate capacity market through May 2005, we used the ComEd capacity price ($27.98/MW-day) for eleven months and the PJM capacity price ($17.74/MW-day) for one month. Table 2 shows the estimated energy and capacity revenues based on these calculations.

Table 2: Energy[*] and Capacity** Revenues Exelon Nuclear Units in Illinois: July 2004 through June 2005

Plant	Energy Revenue ($M)	Capacity Revenue ($M)	Total Revenue ($M)
Clinton	304	10	314
Dresden	235	8	243
Dresden	243	8	252
LaSalle	324	11	336
LaSalle	319	11	331
Byron	345	12	356
Byron	360	12	371
Quad Cities	178	6	185
Quad Cities	182	6	189
Braidwood	353	12	365
Braidwood	347	12	359
Total	3,191	109	3,300

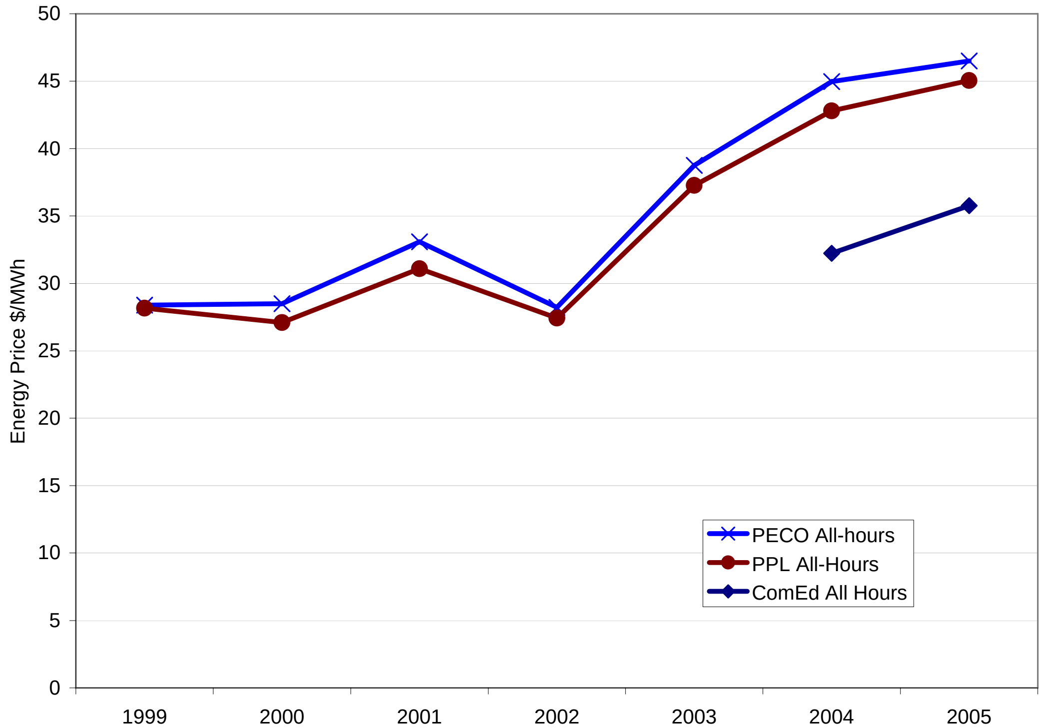
[*] *Assuming continuous output at availability-adjusted level*
** *Based on capacity prices as reported in 2004 PJM State of the Markets Report*

Annual average historical energy market prices for selected PJM regions[10] are shown in Figure 2. These energy prices have risen substantially over the last several years reflecting, primarily, the increase in the cost of natural gas, and this increase has accelerated in the period since. Because nuclear units are not directly affected by the price of gas or other fossil fuels, their production costs are not directly affected by higher gas prices, but the value of their output is. Thus, the increase in electricity market prices has led to a direct, substantial and sustained increase in profitability for Exelon's nuclear units.

[9] PJM State of the Markets Reports are available at http://www.pjm.com/markets/market-monitor/som.html

[10] Calculated from the hourly locational real-time energy price data available on the PJM website

Figure 2



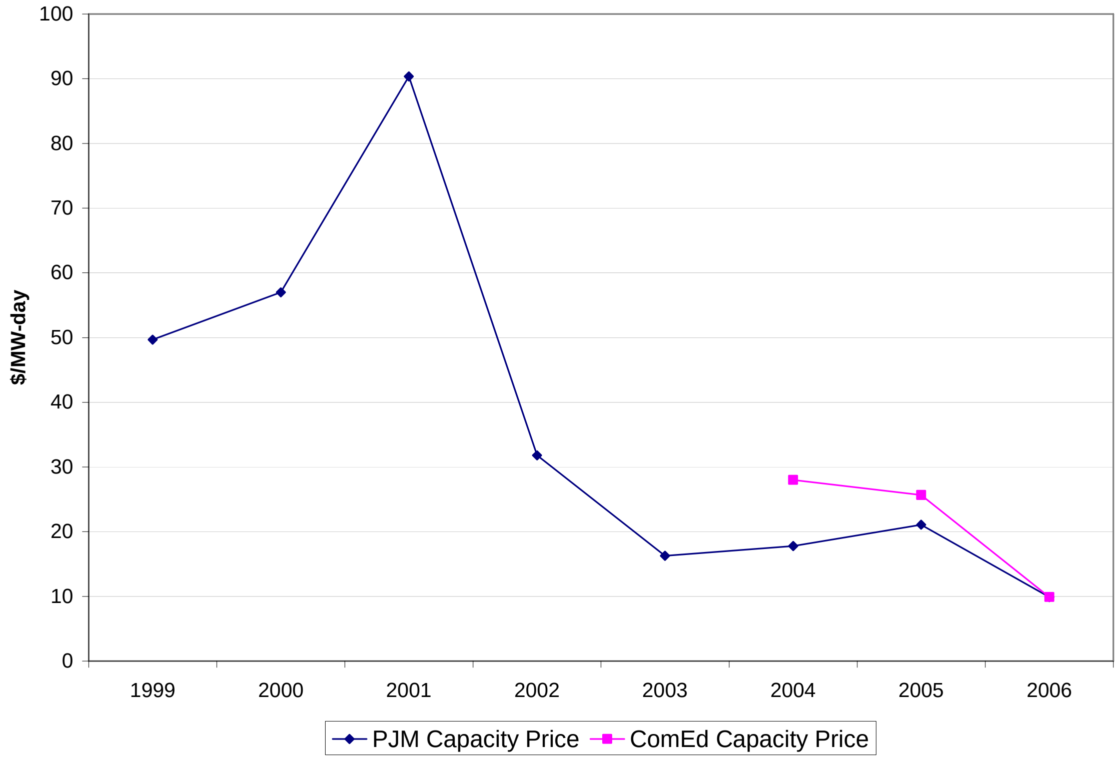
Selected energy prices in PJM (1999-2005). Values for 2005 are based on all hours through August 31. Because ComEd joined PJM only in 2004, market price data for this region are not available for earlier dates.

PJM capacity prices from 1999 through 2006, along with ComEd capacity prices for 2004-2006, are shown in Figure 3. Capacity prices have declined significantly in recent years from initial levels, and this downward trend has continued in a reflection of the surplus capacity in the market as a whole. As of this writing, the most recent clearing price[11] for year-long capacity credits was $5.25/MW-day.

Up until June, 2005, the ComEd area had a separate capacity market from the rest of PJM, with a weighted average price of $27.98 per installed MW-day as opposed to an average of $17.74 per unforced MW-day in PJM proper. According to the 2004 PJM State of the Market report, "the ComEd capacity market results were reasonably competitive in 2004." This is in contrast to the PJM results which were described as "competitive". Market power was described as a "serious concern" in both capacity markets.

[11] Clearing price on May 23, 2005 for capacity from June, 2005 through May, 2006; capacity market outcomes are available at *http://www.pjm.com/markets/capacity-credit/market-results.html*

Figure 3



Capacity Prices in PJM, 1999-2006. Prices from 1999-2004 are as reported in the PJM 2004 State of the Markets Report. Prices for 2005 and 2006 are weighted average values for one-year capacity contracts (June through May) as reported on the PJM website (***http://www.pjm.com/markets/capacity-credit/market-results.html***.) Prices reported as 2006, for example, are for the period June 2005 through May 2006. The NICA capacity market was merged into the PJM market on June 1, 2005.

Market Revenue Scenarios

We calculated future market revenues for the Exelon nuclear stations assuming the quantities of energy and capacity sold for the July-04 to June-05 year would remain constant. PJM market prices for energy are assumed to remain high in the near to mid-term future, as they depend on the cost of natural gas which is considered unlikely to decline in the short run[12]. We thus used 2004-2005 data as the future energy price for all three scenarios.

For capacity market prices following recent market trends ("Last Year") case, we use capacity market prices as shown in the 2004 State of the Markets Report and shown

[12] PJM market energy prices are up for a number of fundamental reasons and are widely considered unlikely to return to pre-2002 levels so we selected an average of 2002-2004 energy prices for the three cases. In fact, given recent trend in fossil fuel prices, the values used here are almost certainly low.

in Figure 3 for ComEd in 2004. We also consider average capacity prices for the period 1999 through 2004 ("Last Six Years") and capacity prices based on the most recent one-year capacity credit market clearing price reported by PJM ("Current") as of this writing[13]. Finally, we consider two scenarios based on the proposed RPM system. These are the expected equilibrium price ("RPM Target"), based on the per-MW carrying charges of a new CT unit net of energy and ancillary service revenues, and the proposed upper limit in the case of a capacity shortfall ("RPM Maximum"), based on twice these carrying charges, again net of energy market revenues[14]. These capacity prices are shown in Table 3.

To estimate what these capacity prices imply for Exelon's nuclear fleet, we calculated market revenues for Exelon's power stations under each of the capacity market price scenarios shown in Table 3. These revenues are shown in Table 4, and they are put into context as a percent of total revenues (energy plus capacity) in Table 5. The total capacity revenues from Table 4 are shown graphically in Figure 4.

Table 3: Capacity price scenarios

Case		Price ($/MW-d)
Last Year	$	27.13
Last Six Years	$	46.23
Current	$	5.25
RPM Target	$	124.97
RPM Maximum	$	327.35

[13] For the period June 2005 through May 2006, market dated May 23, 2005. See http://www.pjm.com/pub/capacity_credit_market/downloads/stat.csv

[14] See the draft proposal circulated by the PJM-RAM stakeholder working group: http://www.pjm.com/committees/working-groups/pjmramwg/downloads/pjm-demand-curve.xls. The target IRM is 15% above peak demand. According to this draft, "At 1% above IRM, the price is based on ONE time Cost of New Entry less E&AS Revenues… At 3% below IRM, the price is based on TWO times Cost of New Entry less E&AS Revenues." As proposed in PJM's filing of 8/31/05, the price falls to zero at 5% above IRM.

PJM's filing also specifies that the adjustment for energy and ancillary services (E&AS) revenues will be based on a six-year average of estimated historical E&AS Revenues for a proxy peaker, located in the region of interest. Under conditions of scarcity it is likely that this E&AS adjustment would rise because energy prices would rise, and the proxy peaker would presumably show a higher capacity factor. This would temper the RPM capacity price somewhat, although this effect would be limited due to the use of six-year averaging. We have not tried to estimate the E&AS adjustment during scarcity; instead we have used the same constant adjustment that PJM provided in the draft proposal, and that was used by the Johns Hopkins University model supporting the PJM filing.

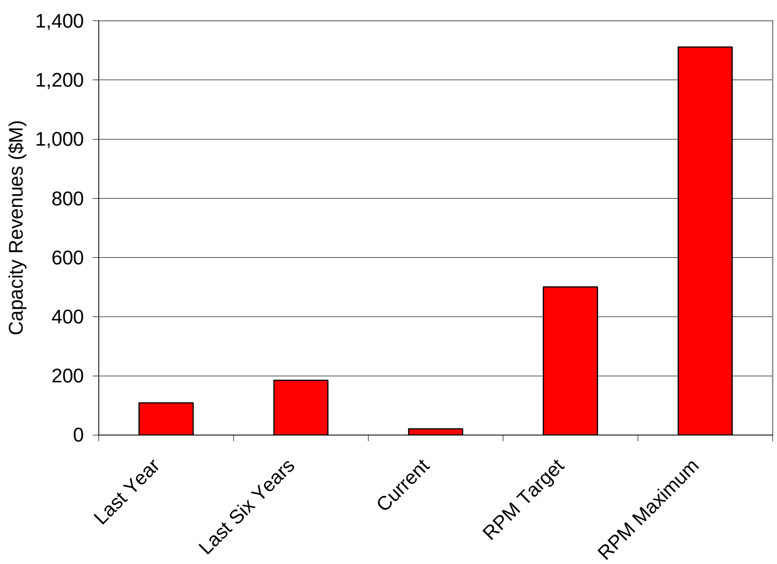
Table 4. Projected capacity revenues for Exelon nuclear plants ($million)

Scenario	Clinton	Dresden	LaSalle	Byron	Quad Cities	Braidwood	Total
Last Year	$ 10.1	$ 16.8	$ 22.4	$ 23.3	$ 12.7	$ 23.4	$ 109
Last Six Years	$ 17.2	$ 28.7	$ 38.1	$ 39.8	$ 21.6	$ 39.9	$ 185
Current	$ 1.9	$ 3.3	$ 4.3	$ 4.5	$ 2.5	$ 4.5	$ 21
RPM Target	$ 46.4	$ 77.5	$ 103.1	$ 107.5	$ 58.5	$ 107.7	$ 501
RPM Maximum	$ 121.5	$ 203.1	$ 270.0	$ 281.5	$ 153.2	$ 282.2	$ 1,312
Energy Revenue	$ 304	$ 478	$ 644	$ 704	$ 361	$ 700	$ 3,191

Table 5. Capacity revenue as a percentage of total revenue

Scenario	Clinton	Dresden	LaSalle	Byron	Quad Cities	Braidwood	Total
Last Year	3.2%	3.4%	3.4%	3.2%	3.4%	3.2%	3.3%
Last Six Years	5.3%	5.7%	5.6%	5.3%	5.7%	5.4%	5.5%
Current	0.6%	0.7%	0.7%	0.6%	0.7%	0.6%	0.7%
RPM Target	13.2%	14.0%	13.8%	13.2%	14.0%	13.3%	13.6%
RPM Maximum	28.6%	29.8%	29.5%	28.6%	29.8%	28.7%	29.1%

Figure 4



Projected annual capacity revenues for existing Exelon nuclear fleet in Illinois, assuming capacity price scenarios from Table 3. *Last Year:* capacity prices as reported in AEO 2004; *Last Six Years:* Average capacity price in PJM, 1999-2004; *Current:* Most recent one-year contract for capacity reported by PJM, for period June 2005 through May 2006; *RPM Target:* expected equilibrium capacity price under RPM; *RPM Maximum:* maximum capacity price under RPM, reached if reserves fall 3% or more below IRM target.

As seen in Figure 4, Exelon's capacity revenues under RPM would exceed the expected capacity payments under any of the historical capacity price scenarios. This is by design, as the purpose of RPM is to institute an administratively-determined capacity price which is greater than the current market price. The target RPM price when all capacity requirements are met, with neither surplus nor shortfall, would yield Exelon $390 million more per year in capacity payments for these units than under the market price of last year. Under a shortfall situation, these annual payments could be as much as $1.2 billion above the recent market.

The capacity represented by these plants was substantially funded by ratepayers under cost of service rates and further subsidized through transition charges. These plants are highly profitable in the energy market even without capacity payments. They are not at risk of retiring in the near future for economic reasons, nor are they located in areas in which generating capacity is in short supply. Exelon would not have to build a single MW of new capacity to receive these payments, and in fact would diminish the revenue stream were they to do so. Regardless, the design of the RPM system is to award all capacity, existing or new, profitable or marginal, the same payment for capacity on a per-MW basis. The vast majority of this money would be paid to owners of existing base load units such as Exelon's. These payments, because they bear no relation to any investment in new capacity, would amount to an excessive, ratepayer-funded artifact of an inefficient and poorly targeted approach to capacity pricing.

VI. Rate Impact

What does it mean for consumers if Exelon is paid hundreds of millions of dollars more in capacity payments for its existing nuclear generating units in Illinois? It is difficult to answer this question precisely because these payments would be blended in with capacity payments from throughout PJM, and ultimately funded by ratepayers from throughout this area. However, if we assume that all of the capacity in PJM will receive capacity payments equal to the RPM target price, and that this cost will be spread evenly over all of the MWh of energy sold in PJM, we begin to get an approximation.

According to the PJM system overview[15], PJM has a total generating capacity of 163,806 MW, and delivers total annual energy of 700 million MWh. If all of this capacity were to receive the target price of $124.97/MW-day[16] for 365 days, the total RPM bill for the ratepayers of PJM would be almost $7.5 billion per year. If all of this capacity were purchased instead at the market price for 2004, the bill would have been about $1.6 billion. Thus, at the target price, RPM would amount to a rate increase for PJM ratepayers of over $5 billion every year, paid mostly to existing base load generation.

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[15] *http://www.pjm.com/about/glance.html*

[16] Because RPM is a locational system, the payments would not be the same in all areas. However, the target price would be the same throughout the system.

If these billions were spread over the 700 million MWh served in PJM in a year, it would amount to an average price increase of about $8.40 per MWh *in addition* to all other costs on each consumer's bill, such as energy, delivery, and transmission charges. For perspective, note that for the period July 2004 through June 2006, the average wholesale price of power in Northern Illinois[17] was $35.05. This increase thus represents almost a 25% increase in the wholesale price of power.

Almost all of this rate increase would go to fund existing, profitable generating capacity at a rate well above the observed market price. If it failed to encourage new capacity and the market fell into shortage, which is not an unlikely outcome, the total capacity bill could be as high as $19.6 billion per year, or an increase of over $25 per MWh compared to capacity prices for 2004. This would represent an increase of over 70% in the wholesale cost of power.

These capacity payments (and those under the current system) are shown in Table 6, along with the average per-MW cost of capacity that they imply for each customer. Given this dramatic increase in capacity payments under RPM, one would like some assurance that this system was the most efficient way to meet capacity requirements, and that it was accepted as such by the PJM stakeholders. In fact, neither of these is the case.

Table 6. PJM-wide capacity payments and per-MW cost to consumers

Case	System-wide Capacity Payments ($million)	Capacity Payments in $/ MWh
Recent	$ 1,623	$ 2.32
Historic	$ 2,766	$ 3.95
Current	$ 314	$ 0.45
RPM Target	$ 7,477	$ 10.68
RPM Maximum	$ 19,585	$ 27.98

VII. Discussion and Conclusions

A comparison of capacity revenues based on the various scenarios considered shows that under RPM, by design, the administratively determined capacity payments to all generators in PJM would be much higher than the prices produced by the current capacity market. Because this administrative price is intended to simulate a "clearing price," it would be paid to all generating units, including those which had been generously funded by ratepayers through cost-of-service ratemaking and transition charges, and which remain profitable today in the energy and ancillary service markets. Exelon's nuclear fleet falls into this category of existing, ratepayer-funded, profitable plants. Exelon stands to make an additional $390 million per year when the target capacity is reached under RPM, and as much as $1.2 billion per year if and

[17] Average clearing price of the PJM day-ahead market for NICA; see *www.pjm.com*

when the system falls into capacity shortfall. In contrast, a typical peaking unit which might be built to address real capacity needs, but which requires some form of capacity payments for recovery of capital costs, would receive a small fraction of this amount. In fact, Exelon and other owners of existing, base load generation in PJM would have a compelling financial incentive to ensure that capacity remains at equilibrium or below. Given their dominance in the regional market, it is reasonable to assume that this is within their means.

In terms of rate impacts, at equilibrium the target capacity price would lead to a price increase of about $8.40 for each MWh sold, adding about 25% to the wholesale price of power, and in shortfall would increase the wholesale power cost by over 70%. Economic theory does not offer any rationale for paying this price for all units, new and existing, in the target region. While it might create the appearance of a market clearing price, it is in fact the opposite; nor is it likely to succeed in creating sufficient incentive and price certainty for new generation. In this sense it combines the worst of regulated and unregulated markets. It is an administratively imposed price, immune to market signals, which funnels money to existing generation owners without any administrative requirement for addressing reliability concerns. The only certain outcome of RPM is that it would cost ratepayers much more than should be required to attract sufficient capacity for reliability needs, and that the bulk of this money would have no impact, or perhaps an adverse impact, on investments in needed capacity.

PJM's RPM proposal will provide for a considerable transfer of wealth from ratepayers to owners of existing generation, such as Exelon, without any specific requirement for the provision of new services. This poses serious questions about how an RPM-type compensation mechanism can be considered an efficient means of pursuing a public policy goal, or could possibly produce wholesale power rates that meet the "just and reasonable" standard of the Federal Power Act.