

Resource Investment in Competitive Markets

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PJM Interconnection



A Note on the Organization of this Paper

This study is presented in two parts.

Part 1 (page 6) examines how markets drive resource investment decisions and compares generation entry and exit outcomes under both market and traditionally regulated constructs. The findings show markets do produce efficiencies when left to manage resource entry and exit.

Part 2 (page 35) explores subsidies, regulations, policies and other requirements that may either reward or disadvantage generating resources and how such actions affect the performance of markets. This discussion concludes that the value proposition revealed in Part 1 can be devalued or lost altogether unless coherent public policies are pursued.

Executive Summary

Organized wholesale electricity markets were created to address burgeoning costs of new power generation under the traditional regulatory scheme and to encourage innovation through free-enterprise competition. The discipline of the marketplace promised lower costs and greater efficiencies. Two decades of experience and numerous studies have demonstrated competitive wholesale markets in PJM and elsewhere bring increased operational efficiency and innovation, resulting from transparent market prices and the benefits of single, independent dispatch across a broad region. These benefits are realized through economies of scale that permit optimization of a large and diverse set of resources and load. The resulting efficiencies are measured in reduced heat rates and increased capacity factors.

However, as a host of organic and external factors change the power supply landscape, some have questioned the efficacy of competitive wholesale markets at promoting the most efficient entry and exit of resources – especially compared to traditional utility regulation with administrative planning and direction, such as under a state-integrated resource plan. Various forces, including federal and state public policies, low-priced domestic natural gas and static or declining levels of wholesale electricity consumption, have challenged incumbent or “legacy” generation resources by increasing operating costs, creating capital investment needs and reducing revenues realized in PJM’s energy, capacity and ancillary service markets. For the least efficient of these resources – older, small coal units, single-unit nuclear stations and older, high-heat-rate natural gas and oil-fired generation – these cost and revenue pressures have threatened their ongoing viability and not unexpectedly have led to retirements in many cases.

Consequently, some observers have questioned whether wholesale markets have forced premature retirements of viable legacy generating resources and whether markets can be relied upon to ensure adequate power supplies in light of the retirements. The questions raised with regard to decisions and outcomes related to the changing nature of the supply portfolio in PJM can be summarized as:

Can we rely on PJM’s organized wholesale electricity market to efficiently and reliably manage the entry and exit of supply resources as external forces create tremendous uncertainty and potential industry transformation?

The goal of this paper is to answer this question. In doing so, this paper does not present itself as an exhaustive or scientific analysis of what are complex issues characterized by numerous variables. In some cases, the value proposition brought to the generation investment decision by competitive markets can be shown with a high degree of confidence. In other cases, the relative advantage of a competitive versus a regulated paradigm in efficiently bringing in new generation and exiting inefficient generation is more arguable. Finally, certain challenges and difficult outcomes necessarily result from the operation of PJM markets in driving investment decisions – challenges and difficulties involving choices between often-competing social and political interests. In contrast, when investment decisions are driven by utilities and their regulators, a trade-off between diverging policy interests can be made directly and explicitly, though not necessarily from a well-informed understanding of the trade-off.

Collectively, the analyses show that the PJM markets are efficiently and reliably managing entry and exit, even while adapting to changing circumstances.

Entry of New Resources

The markets do well in attracting new entry at an efficient cost. Competition lowers costs and excludes technologies with inappropriately high costs. Markets transparently evaluate the economics of proposed projects, and projects that are uneconomical are not built. Importantly, in the market paradigm risk is shouldered and managed by the supplier, not the customer. A financial analysis based on tools of modern portfolio theory was undertaken to try to quantify (in broad terms) the value customers receive in avoiding such risk. This analysis indicates that allowed returns on equity in regulated generation are notably higher than the models would predict given the lower risks relative to merchant investors.

Strong evidence supports the belief that markets are providing adequate returns to incent new generation investment where warranted. For the years 2010-2015 approximately 134,000 MW of proposed natural gas generation entered the PJM generation queue. There now are approximately 74,000 MW in active development, 19,500 MW in service, 3,500 MW in partial service and 35,000 MW under construction. Beyond natural gas generation, the markets are also driving investment in innovative technologies with lower capital costs, providing benefits to consumers.

Innovation

PJM markets provide an accommodating, transparent environment that allows any project or technology to demonstrate its value to the customer based on the combination of capital costs, risks and value, which collectively determine whether a project will flourish or fail fairly based on its merit. Markets do well in pricing operational attributes and innovations of new technologies – generation, storage or demand side – that provide the desired attributes more effectively and economically. Many investment risks can be efficiently managed through financing structures and through hedging tools available in PJM markets and through instruments that have evolved in the greater “ecosystem” of supporting bilateral and exchange-traded commodity markets.

Exit of Resources

No evidence suggests the PJM markets inadequately compensate legacy units and thus are forcing a premature retirement of economically viable generators. PJM's markets are producing prices that are efficiently and reliably signaling the exit of uneconomic legacy resources and the entry of efficient, new resources. A statistical examination of retirement data in PJM compared to regulated environments refutes any assertion that PJM markets are prematurely retiring economically viable generation. When faced with similar capital investment requirements, generator retirements are roughly comparable in market and regulated environments.

In PJM, the decision to shutter a generating station, perhaps before the end of its operationally useful life or the term of its operating permit, is based on market forces – more precisely the owner's assessment of whether the market will provide revenues sufficient to meet the facility's going-forward operating costs. PJM's markets produce transparent prices that provide clear benchmarks for evaluating the continuing economic viability of generation, even for utilities and regulators in those PJM states that have retained a traditional, rate-base regime.

Markets and Public Policy

Realizing the “investment efficiency” advantages of PJM markets can require policymakers to accept tough choices and trade-offs because efficient market outcomes may inflict harm to other policy objectives. Policymakers must weigh these trade-offs but should understand that pursuing individual actions that defeat efficient market outcomes can thwart effective operation of the market. One likely result is that the market no longer can be relied upon to efficiently and effectively provide price signals to achieve efficient and reliable resource entry and exit. This paper acknowledges the widespread existence of subsidies of all sorts that influence PJM market outcomes.

PJM's mission is to provide for a reliable and efficient wholesale power supply. The markets it designs and administers to accomplish this mission do not necessarily promote and may even conflict with other valid public policy interests that state and federal lawmakers and regulators may pursue to meet environmental, social and political interests distinct from the markets' singular mission to deliver the most cost-efficient resources needed to serve customers reliably.

Although PJM markets are efficiently and reliably handling a changing resource mix resulting from forces currently affecting the industry, PJM's continuing ability to deploy market forces to handle this responsibility is threatened if actions taken by lawmakers and regulators to promote other policy interests are pursued in a way that materially distorts price outcomes in PJM's capacity and energy markets.

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Introduction

Before electric industry restructuring and the introduction of wholesale competition, the electricity industry operated exclusively under rate-of-return or cost-of-service regulation with each vertically integrated utility operating effectively stand-alone, albeit interconnected, systems. This paradigm ushered electrification into our daily lives and did so with declining retail rates and declining average costs in real-dollar terms until the early 1970s.¹

However, from the early 1970s to the advent of electricity industry restructuring with the Energy Policy Act of 1992, the industry witnessed overbuilding of generation facilities to serve load, poor performance of the nuclear generation fleet and expensive long-term contracts under the Public Utility Regulatory Policy Act of 1978. All of the above led to rising electricity rates in real terms after nearly 60 years of declining rates and average costs, with the risks of these decisions borne almost entirely by the ratepayers.²

Wholesale competition, spurred by FERC Orders 888 and 889 in 1996 within the context of independent system operators (ISOs), and later regional transmission organizations (RTOs), was designed to bring greater efficiencies in operations, reducing generation operating costs and improving generator performance. Moreover, such a regime has the effect of shifting the risk of poor performance and decisions from the ratepayers back to the owners of generation.

However, since early in this period of restructuring, debates have continued over the relative merits of the competitive market model versus the traditionally regulated model. This debate intensified during the California power crisis in 2000-2001. The debate continues as power prices swing from one extreme to another due first to growing and now to falling demand and natural gas prices.

In the course of this debate, academic economists, through sophisticated modeling and statistical techniques, found that the move to wholesale competition under the ISO/RTO model brought efficiency gains in overall system operations and reduced costs – or found greater efficiencies for the existing generation fleet through improved operating costs, fuel-use efficiency and availability and performance. These findings, published in numerous academic papers and studies, demonstrate what this paper refers to as the “operational” benefits realized by competitive markets.

While these findings are recapped in summary form below, none of the aforementioned economic studies examines closely the role of market forces in bringing about new entry or the retirement/exit of resources. So, while compelling evidence reveals that the ISO/RTO structure more efficiently manages an existing portfolio of resources, the less scrutinized question asked here is whether that model is more effective in determining what goes into that portfolio. Do competitive wholesale power markets lead to more efficient and cost-effective capital investment decisions for new entry, retirement and investment in existing resources to remain in commercial operation? The focus here is to examine the “investment” benefits of competitive electricity markets.

¹ See United States Energy Information Administration (EIA), *Annual Energy Review 2011*, DOE/EIA-0384(2011), September 2012, Figure 8.10, p. 254 <http://www.eia.gov/totalenergy/data/annual/pdf/aer.pdf>.

² *Id.* Nominal retail rates were, on average, more than three times higher in 1992 than in 1970, and real electricity prices remained approximately 25 percent higher than they were in 1970. Literature is replete with examples through the 1970s and 1980s of states struggling to manage out-of-market PURPA contracts and nuclear plant cost overruns by orders of magnitude from initially approved budgets. Examples of these regulatory misadventures during that time period are frequent and well documented. They are raised here to remind the reader of the challenges that face regulators in picking winners and losers and why instilling competitive forces into the industry took hold.

Gains Realized by Wholesale Markets – “Operational Efficiencies”

The development of ISOs and RTOs brought scale and geographic scope economies to wholesale power transactions and operations. The scale economies come from implementing security constrained unit commitment and economic dispatch across wider regions allowing lower overall costs of system operation by eliminating seams, reducing transaction costs and permitting a free flow of lower-cost energy across the wider region. Additionally ISO/RTOs bring economies of scale to resource adequacy and transmission planning across a much wider region rather than looking at smaller systems in isolation.

A Government Accountability Office study in 2008 compared the costs of operating ISO/RTOs across the United States and recommended that there be some attempt at measuring the benefits for these costs.³ The Midcontinent Independent System Operator estimates a cumulative benefit to customers in that area from 2007 through 2015 to be \$12.2-\$16.8 billion.⁴ PJM estimates the total annual benefits overall to customers in its footprint of to be in the range of \$2.8-\$3.1 billion.⁵ In PJM this value translates to just under \$4/megawatt-hour contrasted against a PJM administrative cost of \$0.32/MWh or a more than tenfold return on the investment PJM members make each year.⁶

Efficiency gains with regard to dispatch have been shown prominently in the academic literature by Mansur and White (2012)⁷, Wolak (2011)⁸ and Joskow (2006).⁹

Figure 1 below reproduced from Mansur and White clearly shows that the impact of expanding the scope of RTO operations, in the case the integration of AEP and Dayton Power and Light, increases flows of energy from west to east as lower-cost energy from the Midwest is now more easily available to serve load in the eastern part of the PJM footprint. The resulting efficiencies produced benefits for all consumers.

³ By way of example, in 2008, the GAO summarized competing expert reports analyzing the benefits of electricity restructuring as an appendix to: *FERC Could Take Additional Steps to Analyze Regional Transmission Organizations' Benefits and Performance* (GAO-08-987, Sept. 2008), at 78. Online at: <http://www.gao.gov/new.items/d08987.pdf>

⁴ Midcontinent Independent System Operator, *Value Proposition*. Online at <https://www.misoenergy.org/WhatWeDo/ValueProposition/Pages/ValueProposition.aspx>.

⁵ PJM Interconnection, LLC. *PJM Value Proposition* estimates the value is \$2.8-\$3.1 billion per year. Online at <http://www.pjm.com/about-pjm/value-proposition.aspx>.

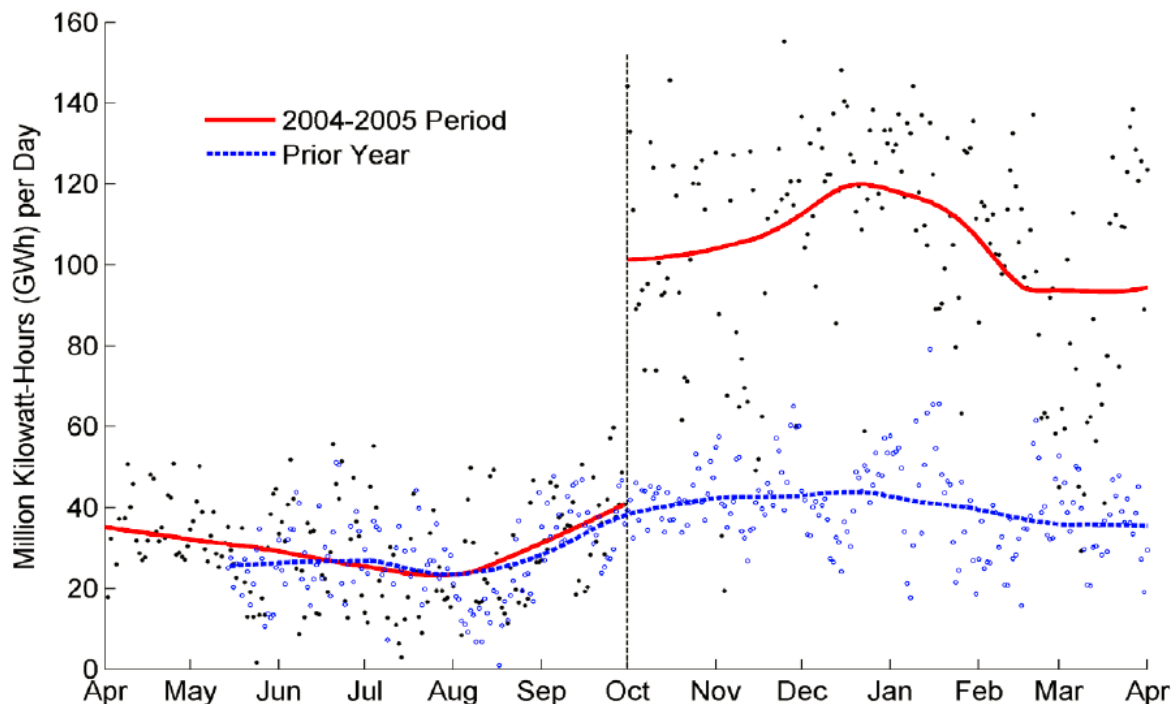
⁶ For the total energy in PJM in 2014 of 795,519,000 MWh this comes out to \$3.52-\$3.90/MWh. See *PJM Load Forecast Report, January 2016*, Table F-2, p. 94. Online at <http://www.pjm.com/~media/documents/reports/2016-load-report.ashx>. PJM also publishes each month and presents to the PJM Members Committee a report summarizing market outcomes with some historic data for context. See Paul M. Sotkiewicz, *Markets Report*, February 22, 2016, p. 6. Online at <http://www.pjm.com/~media/committees-groups/committees/mc/20160222-webinar/20160222-item-07a-markets-report.ashx>.

⁷ Mansur, Erin T and White, Matthew W., “Market Organization and Efficiency in Electricity Markets”. Dartmouth University Working Paper, January 2012. Online at http://www.dartmouth.edu/~mansur/papers/mansur_white_pjmaep.pdf.

⁸ Wolak, Frank A. 2011a. “Measuring the Benefits of Greater Spatial Granularity in Short-Term Pricing in Wholesale Electricity Markets”, *American Economic Review Papers & Proceedings*, Volume 101, pp. 247-252, 2011.

⁹ Joskow Paul L. “Markets for power in the United States: An interim assessment.” *The Energy Journal* Volume 27: pp. 1-36, 2006.

Figure 1. Day-Ahead Net Exports from Midwest to East (PJM) before and After the Integration of AEP and Dayton Power and Light¹⁰



In addition to the operational and planning economies of scale and geographic scope, competitive incentives from wholesale power markets have resulted in more efficient generator operation. Lucas and Wolfram document the improvement in nuclear generator performance due to units operating in a competitive paradigm.¹¹ They determine that nuclear units subject to competitive pressures have improved availability and shortened their refueling outage times leading to a 10 percent gain in operating efficiency such that these units in aggregate have produced about 4 million MWh more energy, with a market value of \$2.5 billion and an implied carbon dioxide emissions reduction of 40 million metric tons. Bushnell and Wolfram document efficiency gains for fossil-fired generating units that equate to a 2 percent reduction in heat rates.¹² Finally, Fabrizio, Rose and Wolfram show that generating units subject to competitive forces and incentives reduced labor costs and other fixed operating costs compared to generating resources that remained under the traditional cost-of-service regulatory treatment.¹³

Evidence supports the assertion that ISO/RTO markets act quickly (*i.e.*, without “regulatory lag”) to reflect changed input costs in wholesale energy prices. Average wholesale energy prices in PJM, for example, fell by about 32 percent in 2015

¹⁰ Mansur and White (2012), Figure 2, p. 55

¹¹ Davis, Lucas W. and Wolfram, Catherine, “Deregulation, Consolidation, And Efficiency: Evidence From U.S. Nuclear Power”, *American Economic Journal: Applied Economics*, Vol. 4, pp. 194-225, 2012.

¹² Bushnell, James B. and Wolfram, Catherine. “Ownership Change, Incentives and Plant Efficiency: The Divestiture of U.S. Electric Generation Plants,” *CSEM Working Paper Number 140*, March 2005. Online at http://faculty.haas.berkeley.edu/wolfram/Papers/Divest_0331.pdf.

¹³ Fabrizio, Kira R., Rose, Nancy L. and Wolfram, Catherine D. 2007. “Do Markets Reduce Costs? Assessing the Impact of Regulatory Restructuring on U.S. Electric Generation Efficiency.” *American Economic Review*, Vol. 97, No. 4, pp. 1250-1277

compared to prices in 2014, driven by declining natural gas prices during that period and the increased incidence of natural gas generation setting the marginal price for energy in PJM.¹⁴

In short, while the extent of these “operational” benefits might be subject to continuing debate, it is generally accepted that distinct efficiencies are realized through a transparent, independent dispatch and optimization over a broad geographic area to capture advantages of scale and portfolio arising from a diverse weather, load and asset mix. While these studies and findings, including PJM’s own assessment of its operational value proposition, show optimization of a given portfolio of energy resources, they say little about whether this portfolio reflects the most efficient, cost-effective set of resources.

A Different Question: Gains Realized by Organized Wholesale Markets – “Investment Efficiencies”

Different ISO/RTOs take different approaches to ensure the most efficient, cost-effective set of resources is established and maintained. In certain ISO/RTOs, decisions as to what resources comprise the resource portfolio are left largely to state regulators, who manage the question of resource exit and entry by traditional cost-of-service regulatory mechanisms, including integrated resource planning or by state-administered resource procurement practices.¹⁵ By contrast in PJM, based to a degree on historical decisions made by various states to introduce retail competition and stimulate merchant competition of supply, market forces (notably the PJM Reliability Pricing Model) signal the efficient exit of legacy resources and entry of new resources.

Competitive wholesale electricity markets should bring about more efficient and competitive resource entry, exit, and retention results for two reasons:

1. There are fewer barriers to entry or exit in the competitive model, in contrast to regulated regimes where entry and exit is managed through a single franchised monopolist.
2. Profitability in a competitive paradigm requires minimizing costs, including investment costs; however, under the traditional cost-of-service structure, profits can be increased by increasing capital spending, and operating expenses generally are passed through to customers on a dollar-for-dollar basis.

Moreover, competitive markets shift the risk inherent in investment decisions from ratepayers to the owners of generation. Competition among merchant investors competing with each other should work to reduce the returns required on invested capital in contrast to administratively fixing an allowed return on rate base through a regulatory proceeding. Finally, an open and competitive market should better attract investment in superior innovations particularly where the operational attributes of such technologies, which are of value to the system operator, are explicitly paid as capacity, energy or ancillary services by market rules. The market also will work to cut off overly risky or costly investments long before they are completed.

¹⁴ Monitoring Analytics, *PJM 2015 State of the Market Report, Volume 2: Detailed Analysis*, March 10, 2016, p. 16, Table 1-8 for the change in energy prices. Figure 3-45 p. 175 shows the reduction in gas prices, and Tables 3-66, 3-67, 3-68 show the Independent Market Monitor-measured change in contribution of gas prices to wholesale energy prices.

¹⁵ In the MISO, Southwest Power Pool and California-ISO markets the value proposition of the ISO/RTO market is essentially confined to what this paper describes as the “operational efficiencies” that come from optimizing a given resource portfolio. ISO New England (ISO-NE) offers an example of an organized market that additionally relies on market tools (ISO-NE’s forward capacity market) to establish and maintain an efficient resource portfolio. PJM similarly relies on its capacity market (the Reliability Pricing Model) to meet this same objective. But, because PJM covers a geography that includes several states which have retained regulatory control over the decisions surrounding generation exit and entry, PJM is better regarded as a hybrid of jurisdictions – with some states relying on PJM’s market to signal resource exit and entry and others relying less on these forces and more on traditional cost-of-service regulation.

Part 1 of this paper addresses the efficiency and cost-effectiveness of generation investment decisions. This paper is meant to complement and add to existing academic literature and findings – work that has examined the “operational efficiencies” of organized markets, but not empirically addressed the larger investment question. It also responds to economic and policy-driven events that have re-ignited questions about “whether markets work” or if “markets are broken.”

The analysis presented in this paper is not meant to settle definitively whether markets are resulting in better and more cost-effective capital investment decisions. Rather, it critically examines the data and other evidence regarding resource investment decisions in the context of what is known about the economic incentives and allocation of risks provided by competitive wholesale power markets and traditional regulatory regimes. The paper compares new combined cycle investment supported by revenues expected from the PJM markets to this same kind of investment supported by full cost-of-service rate regulation. It then examines resource exit, employing statistical modeling tools to compare retirement decisions in PJM with those in a traditionally regulated, non-ISO/RTO environment while controlling for other factors that could influence retirement such as compliance with the Mercury and Air Toxics Standards.

Part 2 then discusses the policies and practices that fall outside the direct purview of competitive wholesale power markets and how these policy choices can affect the ability of wholesale power markets to achieve the most efficient and cost-effective outcomes. While not supporting or opposing particular policy choices, Part 2 explores how various policies integrate with and affect the operation of wholesale power markets in general and specifically in the PJM context.

Part 2 provides the real-world policy context in which the incentives for efficient investment decisions can be reinforced, preserved or undone. Part 2 also provides context for the implied re-allocation of investment risks from generation owners and developers back to ratepayers associated with various policy choices that can impact competitive wholesale power markets.

In summary, the different approaches used to establish and maintain resources for the system operator to optimize raise a question central to Part 1 of this paper: are competitive market mechanisms working well in signaling efficient legacy exit and new entry to arrive at the most cost-effective set of resources to meet system needs reliably? A second-order question is considered in Part 2: assuming competitive market mechanisms efficiently establish and maintain a cost-effective set of resources, do these resources represent the “best” portfolio from a political, social and environmental perspective?

PART 1

Organized Electricity Markets Offer Advantages in Making Resource Investment Decisions

Part 1 begins by summarizing in broad terms the theory and policy objectives governing resource entry and exit under both regulated and merchant investment models. It then moves to actual observations and empirical comparison of new entry in both environments, looking first at unconventional or “cutting edge” technologies, and then focusing on the prevailing cost-effective new entry - natural gas-fired, combined-cycle plants. The entry discussion examines the cost of new combined-cycle plants both notionally and then taking into account the cost and price of risks attendant to the investment. This discussion additionally describes tools PJM’s markets offer merchant investors to manage the risks associated with merchant power investment. Part 1 concludes by considering how obsolete or uneconomic legacy investments are exited under both models, empirically examining whether the impact of new federal environmental rules on coal plants is being handled differently under each model.

Theory and Policy behind Investment Decisions in Regulated and Market Environments

Capital allocation and investment decisions for power generation take place under two broad paradigms. Under the regulated cost-of-service paradigm, franchised monopoly utilities make investment decisions through planning processes, such as integrated resource planning programs. These programs are overseen by state public utility commissions where competitive forces are largely absent. Under the market paradigm, diverse market actors independently make generation investment decisions based on market price signals and expected costs and benefits. Between these poles, hybrid examples can be found. Some cost-of-service states instill a measure of competition by requiring incumbent utilities to compare buy-versus-build options and undertake competitive procurement of supply. Still other states operate within organized wholesale markets, yet still rely primarily on traditional utility regulation and integrated resource planning processes, looking to the organized market to provide a competition-based check for their regulatory decisions. Finally, even states that have ceded full responsibility for resource adequacy to organized markets may pursue policies, such as renewable energy certificate requirements that effectively dictate resource investment activities with limited regard for market price signals.

Theories of Entry

An investor-owned utility, governed under “rate-of-return” or “cost-of-service” regulation, earns an administratively determined rate of return on its capital investments less accumulated depreciation. The utility also recovers “prudently incurred” operating expenses.

Regulators determine the allowed rate of return by estimating the utility’s cost of capital. In 1962, Harvey Averch and Leland L. Johnson theoretically posited the incentives and behavior of utilities subjected to rate-of-return regulation. They hypothesized that when allowed return on rate base exceeds a regulated utility’s cost of capital, the regulated utility has an incentive to deploy more capital than necessary because profits are derived from invested capital. In this case, investing

an additional dollar in capital will result in additional profits in the form of return on rate base. Inefficient overinvestment and excessive utility returns result in higher consumer prices.¹⁶

Regulated utilities also are incented to engage with regulators and legislators in rent-seeking behavior¹⁷ to reduce risk and increase returns. Because there is no competitive market discipline in these monopolies, there is no competitive market behavior to counter a tendency to seek increased returns that translate into higher consumer costs.

In contrast, investors in merchant power projects often have access to more information than a public utility commission, and those investors conduct robust risk analyses before agreeing to support a project. If an independent power project receives the support of sophisticated project lenders and ratings agencies, then market forces and the transparency of the markets have enabled those project lenders to make rational and well-informed decisions about the competitiveness of a project. Public utility commissions do not have the same tools at their disposal and, arguably, are more likely to approve suboptimal projects.

The contrast between the two decision-making regimes becomes most evident in the face of uncertainty. The more uncertainty facing an investment, the more value a market can offer in assessing and managing the risks of these uncertainties. This is true whether the uncertainty is from new forces of change (such as lack of consistent load growth or disruptive technologies) or regulatory uncertainty. Greater information, transparency, and multiple actors should assure that market-based investment decision-making will result in a more comprehensive evaluation and better pricing of risk. Markets thus serve as the crucible from which the most robust solutions emerge. In the face of greater uncertainty, traditional regulated decision-making may cling to potentially old and outmoded paradigms that are no longer effective in the new environment. Importantly, the theoretical advantages offered here assume perfect markets. However, in the real-world, electricity markets do not arise naturally and organically. They are rule-driven, synthetic constructs closely overseen by regulators and policymakers and designed to harness competitive forces to drive efficient outcomes.

Theories of Exit

In competitive markets, decisions by generation owners to exit or go forward depend on whether they expect to cover their going-forward costs.¹⁸ Resources will exit if they operate at a loss or their profits cannot justify needed capital investments. In regulated environments it is less evident whether these same forces apply with the same effect because a utility's economics turn on a return on its rate base.

¹⁶ Averch, Harvey and Johnson, Leland L., *Behavior of the Firm Under Regulatory Constraint*, *American Economic Review*, Vol. 52, No. 5, 1962, pp. 1052–1069. Although widely cited and, indeed, often accepted axiomatically, the validity of the Averch-Johnson effect is not universally accepted. See, e.g., Law, S., *Assessing the Averch-Johnson-Wellisz Effect for Regulated Utilities*, *International Journal of Economics and Finance*, Vol. 6, No. 8; 2014. While the empirical observations made in this paper might in places be explained by Averch-Johnson, the examination of the entry and exit of generation in both regulated and merchant environments in this paper shows that both models work comparably and effectively in exiting economically obsolete resources and replacing them with cost-effective new entry. As will be explored later, regulated models, however, do show a tendency, perhaps explained by Averch-Johnson, to embark occasionally on very expensive experiments, and evidence also suggests regulators are paying investors in rate-based generation a return that is not commensurate with their assumed risks.

¹⁷ In economics and in public-choice theory, “rent-seeking” involves seeking to increase one’s share of existing wealth without creating new wealth. Rent-seeking can result in reduced economic efficiency through poor resource allocation, reduced actual wealth creation and other undesirable outcomes.

¹⁸ Going-forward costs include costs required to keep the facility in commercial operation such as general administrative expenses, fixed operation and maintenance cost, insurance, property taxes and labor or material expenses necessary to keep the facility ready to operate and produce energy. Going-forward costs also can include *prospective capital investments* that would be required to keep the generation facility in commercial operation, such as replacement of major equipment (e.g., turbines) or addition of equipment to comply with environmental regulations.

As described below, the options facing a regulated utility confronting the question of exit create incentives which can drive different, but equally undesirable, decisions. Certain scenarios may create an incentive to retain uneconomic resources that should be shuttered, while others can result in precisely the opposite outcome – retiring resources that still have economically useful life in favor of expanded investment in new rate-based resources. According to theory, because cost-of-service regulation biases decisions toward capital-intensive investments and because operating expenses are passed through to ratepayers, a profit-maximizing utility is indifferent to the operating expenses of different options.

Consider a regulated utility deciding whether to undertake a substantial capital investment in a marginally profitable generating facility in order to keep it in operation. One option might be to buy lower-cost capacity and energy from the market, the cost of which is regarded as an operating expense in the regulatory world. The efficient competitive market solution would be to retire the existing generation resource. However, because investing in the plant involves a capital expenditure and because the utility can earn a regulated return on that investment, the regulated utility is incented to retain and invest in its existing asset rather than retire its resource and buy from the market.

If one subscribes to the Averch-Johnson effect, the decision to make an uneconomic investment in an existing plant in lieu of purchasing power from a third party is predictable. Academics have hypothesized how this can happen because regulated environments can be structurally biased in favor of retaining capital once invested and thus reluctant and slow to retire and close assets which are no longer economic.¹⁹ Given the competitive pressures facing the nation's coal fleet, some studies have tended to support this hypothesis²⁰ noting increasing environmental compliance costs and the “new normal” of persistently low natural gas prices.

Conversely, when the utility has the option to shutter a coal plant in favor of capital investment in a new plant, Averch-Johnson may work to quite the opposite effect by prematurely retiring depreciated (but still economic) capital in favor of an expanded rate base. The PJM markets have been charged with this same inefficiency, as some argue the markets are providing inadequate revenues (relative to a regulated construct) and thus are overly aggressive in retiring generation (for example, existing coal-fired generation).

This paper does not seek to prove or disprove any of the foregoing hypotheses, including the Averch-Johnson effect. Nevertheless, the academic debate is a helpful backdrop when considering the fundamental question posed by this paper: do empirical observations indicate whether markets result in efficient entry and exit outcomes for resources needed to assure reliability?

Resource Entry: Costs and Risk-Adjusted Returns in PJM Markets Compared to Regulated Environments

With notable exceptions, new entry generation in the United States over the past several years and for the immediately foreseeable future can be classified as investment in either (i) renewable or emerging technologies, or (ii) natural gas

¹⁹ See, e.g., Hsu, *Capital Rigidities, Latent Externalities*, 51 Houtson Law Review 720 (Feb. 2014). Hsu's observations on the “stranded cost” payments agreed to by state regulators as they transitioned in the 1990s from regulated capital to merchant capital is instructive to consider in light of sequels currently playing out in certain states as some legacy coal and nuclear units face obsolescence. Hsu notes wryly: “Transition relief, based on a misguided intuition, has made the obsolescence of capital everybody's problem. Everybody, that is, except the owners of obsolescent capital.”

²⁰ See, e.g., *Ripe for Retirement, The Case for Closing America's Costliest Coal Plants*, Union of Concerned Scientists (Nov. 2012) examined coal plants operating in the face of economics that should, accordingly to the study, have forced closure. The study concluded that the most so-called “ripe-for-retirement generators” were located “primarily in the Southeast and Midwest, with the top five (in order) being Georgia, Alabama, Tennessee, Florida, and Michigan.” These states generally are operating outside organized wholesale electricity markets. Study online at: http://www.ucsusa.org/sites/default/files/legacy/assets/documents/clean_energy/Ripe-for-Retirement-Full-Report.pdf

combined-cycle plants. The section below compares new entry in regulated versus market regimes, first by examining other resource types, including renewable and emerging technologies, before turning to combined-cycle generation.

Emerging or Unconventional Technologies

Markets determine whether the theoretical promise of a new innovation is realized under real-world operating conditions.²¹ This principle applies to low-capital resources such as renewables as well as large-scale, capital-intensive projects. Conversely, in a regulated environment, the incumbent utility stands as a gatekeeper to entry. Elements of the regulated structure (the Averch-Johnson effect) likely create disincentives for incumbent utilities to pursue emerging technology solutions if they involve a low capital outlay. Given a choice between increasing its operational costs, which are simply passed through without providing a return to the utility, versus investing more capital, the rational utility would choose to invest capital in order to realize greater returns.²²

Other structural aspects of traditional regulated environments also may discourage investment in emerging technologies.

- Although a utility may be motivated to have ratepayers underwrite the theoretical proposition of an unproven technology, the attendant risk that regulators may deny rate recovery if the investment ultimately is deemed imprudent or unnecessary works to perpetuate conventional resource investment.²³
- The value of grid benefits, such as energy or ancillary services, is opaque, making it difficult to evaluate the relative performance of the innovation compared to established or alternative technologies.
- The lack of competition or outright prohibitions against competition (due to the franchise monopoly nature of non-market environments) makes it difficult to test a variety of approaches.

In regulated environments, an unsuccessful innovation could be locked into a utility's rate base for years.²⁴ As evident from the examples noted in Table 1 below, unsuccessful innovation can prove a costly proposition considering the aforementioned bias in favor of large, capital-intensive projects, such as 21st-century nuclear plants and clean coal generation.²⁵ A large failed bet on one technology may crowd out willingness or funding to try an alternate technology that otherwise might have emerged as a true game changer.

²¹ See also, Huntoon, S., *Battery Storage: Drinking the Electric Kool-Aid*, 36 *Public Utilities Fortnightly*, at footnote 3 (January 2016) ("Two-thirds of the country operates under competitive wholesale markets that can function as a check on bad ideas being charged to captive customers (of course captive taxpayers remain at risk).")

²² The incentive structure of regulation thus favors a large capital investment (such as a new, large generating plant) ahead of a small one (such as less capital-intensive technologies or demand response that will reduce volumetric revenues). It also follows that a rational utility will be incentivized to take steps to block these alternatives where possible in order to preserve the need for its preferred larger-scale capital investments.

²³ See, e.g., Lyon, Thomas P., "Regulatory Hindsight Review and Innovation by Electric Utilities", *Journal of Regulatory Economics*, Volume 7, pp. 233-254, 1995.

²⁴ For instance, Long Island ratepayers are still paying for Shoreham Nuclear Power Plant, the \$6 billion nuclear plant that was completed in 1984 but never ran due to safety concerns. *The New York Times*, "Planning the Fate of a Nuclear Plant's Land," John Rather, January 1, 2009. Accessed January 22, 2016, from http://www.nytimes.com/2009/01/04/nyregion/long-island/04shorehamli.html?_r=0

²⁵ The case of "clean coal" or integrated gasification combined-cycle technologies in the United States provides a good recent example. Mississippi Power's long-delayed 582 MW Kemper County facility presently is projected to cost nearly \$6.5 billion, compared to an expected \$2.3 billion when regulators approved the project in 2010. Such a project seems highly unlikely to initiate in a market like PJM's, even taking into account generous subsidies from the Department of Energy, Internal Revenue Service and others. Furthermore, if one did commence, its cancellation well before commercial operation would be inevitable as transparent electricity market prices, driven lower by falling natural gas prices, would make the folly of continued construction funding abundantly evident.

Regulators are aware of these problems. Some have taken steps within their regulatory paradigms to enable newer technologies to come online. Some jurisdictions use constructs such as performance-based regulation, including multiyear rate plans and performance incentive mechanisms, to help overcome the traditional disincentives found in the regulated environment. Regulators examine these kinds of options with the hope of changing the investment decisions that usually result from cost-of-service ratemaking so as to increase adoption of demand response, energy efficiency, distributed resources and so forth. Not surprisingly, these programs tend to become quite proscriptive²⁶ because they often work at odds to the incentives motivating a monopoly utility. Still, for regulators charged with evaluating resource investment options, if located within an organized market they almost certainly will make better informed decisions having ready and transparent market alternatives from which to compare.

In markets like PJM's, innovative technologies, almost without exception, are investments with lower capital costs. Resources such as energy efficiency demand response, small-scale distributed generation, smart inverters, microgrids and battery storage represent the "cutting edge" in PJM. While such new technologies can be found to some extent in regulated environments, they also tend to define "cutting edge" to include investments that are larger (and riskier) by orders of magnitude: the latest generation in nuclear reactors, super-critical coal, coal gasification, carbon capture and sequestration and utility-scale renewable projects.

Next-Generation Nuclear and Coal

As shown below, the capital-intensive investments in innovative technologies made in regulated regimes are expensive from the standpoint of invested capital when compared to conventional new combined cycle.

Table 1. Comparison of Investment Costs for Next Generation Coal and Nuclear vs New Natural Gas

Cost Comparison of Large Scale Generation					
	Project Type	Estimated Cost (\$B)	Size (MW)	Estimated Investment Cost (\$/kw)	Converted to \$/MW-Day
Kemper County	Coal with carbon capture	\$6.5	582	\$11,168	\$3,272
Crescent Dunes	Solar with molten salt storage	\$0.91	110	\$8,200	\$2,402
Watts Bar 2	Nuclear	\$6.1	1,150	\$5,304	\$1,554
Vogtle 3 and 4	Nuclear	\$14	2,230	\$6,700	\$1,963
Prairie States	Supercritical Coal	\$5.0	1,600	\$3,125	\$915
Comparison Generator Benchmark²⁷	Natural Gas Combined Cycle			\$1,400	\$410

²⁶ For a more detailed examination see "Performance-based Regulation in a High Distributed Energy Resources Future" at <http://www.synapse-energy.com/sites/default/files/performance-based-reg-high-der-future.pdf>

²⁷ This value was offered in 2015 testimony to the Public Utilities Commission of Ohio as representing a working benchmark used by IHS CERA. It is referenced in Table 1 only as a generalized point of comparison. In fact, other firms publish ranges lower than this value. See, e.g., Energy & Environmental Economics (E3), *Capital Cost Review of Power Generation Technologies Recommendations for WECC's 10- and 20-Year Studies*, at 17-18 (March 2014) online at: [https://www.wecc.biz/Reliability/2014 TEPPC Generation CapCost Report E3.pdf](https://www.wecc.biz/Reliability/2014%20TEPPC%20Generation%20CapCost%20Report%20E3.pdf). As discussed later in this paper, actual new combined cycle entry in PJM (both merchant and regulated) is coming on-line at costs well below this value.

The conclusion from this table is clear. Investment in high capital, high risk and experimental technologies will not find footing in PJM as they might in regulated regimes. The price of these projects is intolerably high in contrast to the natural gas combined-cycle alternative that today's market offers.

Storage

A cost-effective way to store large volumes of electricity has been described as the industry's "holy grail" which, if found, would transform the industry.²⁸ Despite the broad applicability of grid benefits from storage, the current technology is very concentrated in areas with competitive markets. Approximately 85 percent of the non-pumped-hydro energy storage in the United States is deployed in competitive markets with over half the total located in PJM.²⁹

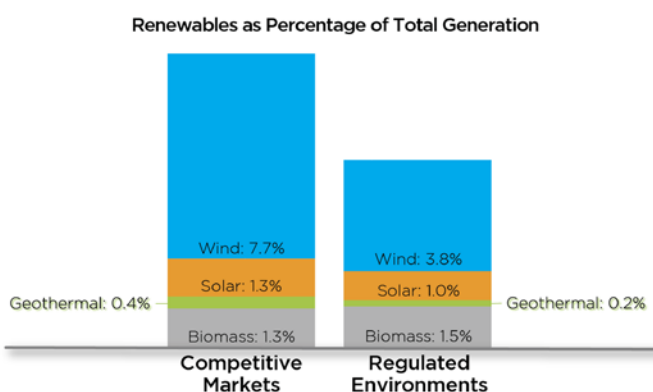
Table 2. Energy Storage in the United States

Market	Energy Storage Deployed (MW) as of Q3 2015
California	5.7
ISO-NE States	5.0
New York	28.0
PJM States	231.2
Texas	44.3
Total, Competitive Markets	344.1
Total, Nationwide	401.0

Renewables

Renewable resource investment is driven as much by tax, financing and other social and environmental policies as it is by economic fundamentals. Nevertheless, comparing non-hydro renewable-resource penetration does suggest that lower economic barriers to entry as well as opportunities to earn operating reserve and frequency regulation compensation, which are both found in market environments, help to attract renewable investment. Figure 2 below shows that as of 2015, renewable penetration is 10.6 percent of total generation in market environments versus 6.5 percent in non-market areas.

Figure 2. Renewable Penetration Levels (2015)³⁰



²⁸ See, e.g. Enskog, D., *Resolving Energy Storage: the Sector's Holy Grail?*, Credit Suisse Newsletter (May 8, 2005) online at: <https://www.credit-suisse.com/us/en/news-and-expertise/economy/articles/news-and-expertise/2015/08/en/resolving-energy-storage-the-sectors-holy-grail.html>.

²⁹ Data from GTM Research/ESA U.S. Energy Storage Monitor.

³⁰ Based on national generation collected from SNL Financial, accessed March, 2016. Comparison ISO/RTO areas vs. non-ISO/RTO areas.

Demand Response

Several attributes of demand response fundamentally distinguish it from typical generation investment made under a traditionally regulated model. Demand response usually involves minuscule capital investment compared to a new generating plant. It reduces the metered flows of wholesale electricity and receives compensation for providing this demand reduction service. This payment model contrasts with generation investors whose returns increase the more kilowatt-hours are flowed. While demand response can never completely substitute for electric generation, it can be a highly effective and valuable means of managing peaks in demand. Many would argue that demand response, like renewables, has been heavily incentivized by subsidies and the level of penetration is driven by these subsidies as well as other societal priorities. These subsidies undeniably have a pronounced effect, as do proscriptive policies in the regulated environment. Nevertheless, the markets serve as an open, transparent platform for demand response to demonstrate its value and for policymakers to evaluate the costs of the policies they support.

Because the entirely different payment model and incentives associated with demand response do not coexist comfortably with the traditional integrated utility model, it again should come as no surprise that the level of demand response overwhelmingly favors market over regulated environments.

Table 3. Potential Peak Reduction in U.S. Demand Response Programs (2014)³¹

Market	2014 Potential Peak Reduction (MW)
California	2,316
ISO – New England States	2,487
New York	1,211
MISO	10,356
PJM States	10,416
Texas	2,100
Total, Competitive Markets	28,934
Total, Nationwide	31,191

The foregoing observations around renewable, demand response and alternate technologies suggest that the open access of the PJM markets provides a platform on which any solution can demonstrate its value. The PJM markets have spoken on the value proposition offered by the latest-generation nuclear and coal technologies. (As explored in Part 2, whether the market should serve as the final word on such questions is open for debate.) Additionally, although PJM and its ISO/RTO peers appear more successful than other areas in attracting innovative and flexible supply and demand resources, drawing any firm conclusions about the relative benefit brought by markets is difficult when the investment decision, in many

³¹ FERC (2015) Assessment of Demand Response and Advanced Metering, online at <http://www.ferc.gov/legal/staff-reports/2015/demand-response.pdf> with additional data from various EIA and ISO/RTO reports.

instances, depends heavily on subsidy. Instead, evaluating new, natural gas-fired combined-cycle investment is a more enlightening comparator.

New Combined-Cycle Plants

In much of the United States a natural gas combined-cycle plant is today's most cost-effective new electricity generation investment. This section considers three important questions arising from this development.

1. Are PJM markets bringing new combined-cycle generation online at a higher or lower total cost than under full cost-of-service regulation?
2. In making such comparisons, how do we measure the value or cost that comes from allocating risk either to investors in the merchant paradigm or to ratepayers in the regulated paradigm?
3. Once the value/cost of risk is accounted for, can we conclude that PJM markets are better at forcing cost control and/or whether PJM's market-clearing dynamics, which cause capital to compete for returns, force a downward pressure on investor returns?

Investing in a power plant presents risks in many forms. All risks have costs that are borne by some party. To illustrate, assume an expensive Italian sports cars dealer is offering its flagship model at two prices: (1) at \$120,000 with only the most minimal warranty allowed by law or (2) at \$130,000 with a full, bumper-to-bumper repair and maintenance warranty for the 10-year life of the vehicle. Depending on one's assessment of the likelihood and cost of repair and maintenance, \$130,000 could be a much more attractive proposition for a buyer than the option of saving \$10,000 up front but assuming the going forward costs of maintenance and risks of repairing an expensive sports car.

In the wholesale electricity realm, the unbundled load serving entity (LSE) and the traditionally integrated utility fall into the role of sports car buyers in our example. The analysis below suggests that customers of a traditional integrated utility company operating under rate regulation may be paying a lower upfront price for new combined-cycle generation but they bear the additional risks (e.g., construction, market, operating, etc.) associated with building and operating that plant over its life. This buyer of generation compares to the customer who elects to pay \$120,000 for the sports car and assumes all ongoing repair and maintenance risk.

In contrast, although LSEs in PJM appear to pay a comparable or marginally higher upfront cost for new combined-cycle plants, any premium paid assures that all market, price, operations, technology and regulatory risks remain with the generation asset investor and are not assumed by the LSE (and its retail customers in turn). Which is the better deal? That depends on pricing the cost of this risk (or the value in avoiding this risk) and then adjusting the purchase price accordingly.

This section first examines costs (the purchase price in this example). It tries to establish representative all-in costs (including debt service and a return on equity) for new combined-cycle generation in both merchant and regulated cases. It examines recent merchant entry in PJM and recent regulated entry both in PJM (Virginia) and outside PJM (Florida) to identify the equivalents for both the \$120,000 and \$130,000 prices used in the sports car example above. In electricity terms, this price can be expressed in an annual revenue requirement (\$/MW-year) and in dollars per installed kilowatt.

Having identified a range of all-in costs representative of each environment, the paper considers risk allocation and the expected returns to investors – each class presenting a dramatically distinct risk profile. As noted, rate regulators calculate and establish revenue requirements based on a certain rate of return on the rate base. This return should account for the fact that investment risks are largely allocated to ratepayers in regulated environments. This situation stands in marked contrast to merchant investment in PJM where the market provides varying and uncertain revenues and return on the

equity investment in a new generating asset. Additionally, the return realized by merchant investors must account for the costs they assume in wearing or managing all risks arising from developing and operating the asset.

In theory, the allocation of risk to the investor as opposed to the customer is more efficient and should lower costs to the consumer because risks will reside with parties positioned to manage those risks, which ultimately may not lie with the merchant investor but with third parties with whom the merchant can transact to lay off risk (for a price). The section concludes by discussing the tools available to manage such risks both within PJM's liquid markets and in supporting secondary markets.

In short, overall costs and returns on invested capital differ in competitive electricity markets from returns in regulated systems. What do these differences say about the competitiveness of one system compared to the other? Does empirical evidence demonstrate that competition forces investors in market environments to lower costs or accept a lower return on equity compared to the regulated monopoly?

Comparing Cost of New Entry in Differing Environments

Recent combined-cycle development in Virginia represents entry under a full cost-of-service paradigm. These new plants have been praised by the industry as extremely well executed by the utility (Dominion Virginia Power) and cost effectively managed by the State Corporation Commission.³² The regulatory process that evaluated and accepted these resources also benefits from unusual transparency as each of the three examples considered below (Brunswick County, Bear Garden and Warren County) were approved with separate rate riders that state a specific annual revenue requirement for each plant. While just a "snapshot," the Virginia plants would seem to reflect the operation of regulation at its best. Therefore, they serve as a fair representative of the overall regulated model against which to compare PJM's market-driven outcomes.

Perhaps surprisingly, determining all-in costs for merchant investment in PJM is more complex. Identifying revenues received by new entry clearing PJM's capacity market is straightforward. The analysis below uses the clearing prices from the 2015/2016 Base Residual Auction³³. These values for the constrained Eastern MAAC³⁴ region calculated at \$167 per MW-day and for the rest of the RTO at \$136 per MW-day. These values then were annualized (multiplied by 365) to arrive at an annual revenue value. However, merchant investment in PJM is not supported solely by revenues received from the capacity market but additionally by net revenues (revenues less costs) realized by selling energy and ancillary services.

Determining infra-marginal returns realized by a generator in PJM's energy and ancillary service markets is a function of the unit's capacity factor, expected locational marginal prices (LMPs) and its operating costs (fuel, variable operations and maintenance). To determine the net energy and ancillary service market revenues that might contribute (along with capacity market revenues) to the fixed costs and return to the asset investor, PJM modeled a cost of new entry for a 656 MW natural gas combined-cycle generator based on 2012-2014 LMPs. In Table 4 below, the first column (PJM Capacity,

³² In December 2015, *Power Engineering* magazine recognized Warren County as its "Project of the Year" and "Best Natural Gas Fired Project." Online at: <http://www.power-eng.com/articles/2015/12/power-engineering-renewable-energy-world-name-2015-power-gen-international-projects-of-the-year.html>

³³ This auction does not reflect the additional performance requirements and other rule changes included in the Capacity Performance initiative. It was selected because 2015/16 more closely aligned to the commercial operations dates of the comparison units in Virginia and Florida.

³⁴ The Eastern MAAC area generally encompasses New Jersey, southeastern Pennsylvania, and the Delmarva peninsula.

Energy and AS Revenues (based on net energy revenues)) reflects both modeled revenues and operating costs.³⁵ Examples in PJM are shown both in Eastern MAAC and in the rest of the RTO.

The second column shows the gross cost of new entry as determined by the auction planning parameters for PJM's 2018/2019 Base Residual Auction. It serves only as a reference price in PJM's capacity market and is levelized over 20 years (as opposed to 30 years for the Virginia and Florida figures).

Finally, as an added point of comparison, Table 4 below shows approximate revenue requirements for three recent combined-cycle projects in Florida.³⁶ These projects show costs higher than those in Virginia and generally higher than the range of plausible costs in PJM. As in Virginia, consumers in Florida are paying these costs plus assuming all other investment risks. But, unlike Virginia, Florida is neither a part of nor adjacent to an organized wholesale market. While many factors undoubtedly could explain why new investment seems to be coming online in Florida at a higher notional cost than in Virginia, it can be surmised that Virginia benefits from the alternate supply options, transparency and discipline offered by PJM's competitive markets. Florida's isolation from an organized market might impede regulators from having a full range of alternatives to consider and to provide a competitive check on regulated new build. These themes are explored further in Part 2.

Table 4. Comparison of New Natural Gas Generation

	PJM ³⁷				Virginia ³⁸			Florida ³⁹		
	PJM Capacity, Energy and AS Revenues (based on net energy revenues)		PJM Gross Cost of New Entry ⁴⁰		Brunswick County	Bear Garden County	Warren County	Cape Canaveral	Riviera	Port Everglades
	RTO	EMAAC	RTO	EMAAC						
Annual Revenue (\$/MW-yr) ⁴¹	124,029	151,418	130,425	132,200	118,810	120,696	97,330	137,750	187,200	169,146

³⁵ Revenues are based on three-year historic averages.

³⁶ This information was obtained from Florida Public Service Commission docket number 120015-EI and the settlement approved on December 13, 2012.

³⁷ Capacity revenues are based on a clearing price of \$136/MW-day in the rest of the RTO and \$167/MW-day in Eastern MAAC from the 2015/2016 Base Residual Auction.

³⁸ Based on 2015 rate rider filings for the 1358 MW Brunswick County facility, 580 MW Bear Garden facility, and 1342 MW Warren County facility. Annual revenue calculations are based on projected annual revenues levelized over 30 years, using a 7 percent discount rate.

³⁹ Based on annual revenue adjustments of \$165.3 million beginning June 2013 for the 1200 MW Cape Canaveral facility, \$234 million beginning June 2014 for the 1250 MW Riviera Beach facility, and \$216 million beginning June 2016 for the 1277 MW Port Everglades facility. These amounts are subject to year-to-year adjustment, and are used here for illustrative purposes only. See, Settlement Agreement approved on December 13, 2012 in Florida Public Service Commission Docket No. 120015-EI.

⁴⁰ PJM 2018/2019 BRA Planning Parameters online at <http://www.pjm.com/~media/markets-ops/rpm/rpm-auction-info/2018-2019-bra-planning-parameters.ashx>.

⁴¹ For PJM, this number represents expected annual revenue as described above based on values from the noted years. For Virginia and Florida, this figure represents a 30 year levelized annual revenue requirement for these units. Out of market revenues (uplift) as well as performance assessment debits or credits under PJM's new Capacity Performance design are examples of market design features that may increase or decrease total net revenues realized by a

It is difficult to compare all-in costs accepted by a regulator for new combined-cycle entry with the same costs incurred by PJM (and in turn its wholesale customers) for this same resource. This analysis necessarily is simplified and does not control for all variables that might fully explain outcomes. Accordingly, any findings should be regarded as indicative and not in any way definitive.

Markets are attracting significant new investment. In PJM, over 15,000 MW of new generation is expected to come online in 2016. This investment is being made based on a range expected market revenues of between \$124,000 and \$151,000 per MW-year. In Table 4 above, the second column (EMAAC) is the high end of the range and reflects higher capacity revenues in constrained capacity areas and market revenues based on three-year historic averages, including energy and ancillary services values that are probably atypically inflated due to high prices experienced during the Polar Vortex period.

These estimates seem reasonable when compared to regulated generation projects of similar size and vintage. The projects in Virginia have an approximate annual revenue requirement of between \$97,000 and \$121,000 per MW-year while those in Florida come in approximately between \$138,000 and \$187,000. These calculations in Table 4 do not attempt to control for geographic costs differences in siting and construction. The costs in the locales in which the Dominion Virginia Power plants were built likely compares more closely to average costs in PJM (*i.e.*, the PJM RTO), and not PJM's Eastern MAAC.⁴² More important, the PJM merchant annual revenue and installed kW values are paid across *all* resources in the system – both to the marginal, highly efficient new entrant and to the older, existing and lower-capacity-factor legacy resources. The values, however, in the regulated cases are plant-specific. The average cost (considering both new and existing units) in Virginia and Florida reasonably can be expected to be higher than the values stated in the table for the state-of-the-art, new plants.

While the table attempts an “apples to apples” comparison of new combined-cycle entry under each model, at best it offers a “red versus green apple” comparison. Nevertheless, the comparison suggests both environments establish new entry at roughly the same costs – with some nominal advantage in favor of the regulated paradigm (at least in Virginia). But, comparing on their face the notional costs between PJM on one hand, and Virginia and Florida on the other, ignores one critical but difficult to quantify cost distinction not captured in the values in Table 4

It is an axiomatic law of finance that risk has cost. If one could price all risks attendant to developing, constructing and operating a new power plant over its economically useful life, one could compare the notional values in Table 4 to “risk-adjusted” values to determine which model delivers consumers the overall better deal when procuring new combined-cycle resources. The nominal advantage seen in Table 4 in favor of the regulated model might disappear, and the balance could shift in favor of the merchant model. The difficulty, of course, lies in pricing this risk. The challenge is heightened now when

generator. No estimates of these speculative and less material elements were included in arriving at the indicative values representing the “annual revenue requirements” paid to resources by the PJM markets.

⁴² By the same token, the higher costs seen with the reported Florida projects are likely explained to some degree by higher costs associated with siting, permitting and developing generation as compared to Virginia. Other locational differences also impact these figures. For example, Florida requires natural gas generating plants to have firm fuel delivery contracts, which serves to escalate their costs relative to combined cycles in other parts of the country. Because the values reported here are intended simply to be indicative, they do not attempt to try to control for locational cost differences. A general sense of the degree such costs vary from one region to the next can be found in *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants*, U.S. Department of Energy, Energy Information Services (April 2013).

today's investments face market, political and regulatory risks, many of which have no historical antecedent that might serve as a starting point for modeling risk.

The following discussion examines how the financial equity markets regard firms operating in merchant versus regulated environments and whether differences here offer insight useful to valuing or pricing the various risks faced when investing in new generation under differing regulatory conditions (merchant or cost-of-service).

Considering Risk and the Cost of Risks Associated with Generation Investment

As with all capital allocation decisions, resource investment decisions are based primarily on the risk-adjusted expected returns of investment alternatives. Understanding the difference in the electricity industry between risk-adjusted expected returns for merchant generation investment and for regulated generation investment is important because each model allocates this risk very differently. This section employs economic and financial models to analyze the risks of and returns on merchant and regulated investment. For readers without a financial background, the results are summarized as follows:

Conclusions

1. Because they do not have ratepayers, the merchant generator must hold and manage all investment risk and thus its cost of equity is higher than for a regulated utility. However, in stronger economic periods, the difference in the cost of equity between merchant investment and regulated utilities is smaller than in weaker economic periods, indicating that investors are less inclined to make a riskier merchant investment during weaker economic periods.
2. Actual returns indicate that merchant generation company returns are statistically consistent with their risk-adjusted expected returns. On the other hand, actual returns for regulated utilities are statistically higher than their risk-adjusted expected returns. It is unclear why there is a significant difference in actual returns over risk-adjusted expected returns that benefits investors in regulated generation.

Analyses of the cost of equity for merchant generators and regulated utilities indicate that financial markets properly seek higher returns from riskier merchant generation investments and confirm that actual returns on merchant generation investment are consistent with such required returns. In addition, those same analyses revealed a significant phenomenon regarding returns for regulated utilities. Based on allowed rates of return on equity in recent cases, regulated utilities exceed the estimated cost of equity by a statistically significant 1.75 to 2.68 percentage points, depending on the model used in each analysis. It is unclear why actual regulated investment earnings are above the risk-adjusted expected rate of return.

3. Overall, economic and financial principles would expect actual returns for merchant generation companies to be higher than on regulated utility investments due to the higher risk attributed to merchant generation investment. However, analyses of actual returns supports that regulated utility companies are earning more than merchant generation companies despite the lower risk profile of regulated utility investments.

Allocation and Pricing of Risk: Regulated Versus Merchant Investment

As noted, one profound difference distinguishing competitive from traditional electricity markets is how the risk of investment is allocated. In a traditional cost-of-service regime, ratepayers underwrite the investment in public utility assets. The regulator is responsible for protecting ratepayers' interest in assuming only the risks of prudently made, used and useful investments. This is a difficult job and one that suffers from certain inherent structural flaws that regulatory economists and policymakers have examined often and in great length over several decades.

A central question is whether the regulatory paradigm to support electric infrastructure investment respects one of the basic tenets of finance theory regarding risk: that the most efficient outcomes result from structures (law, regulation, private contracting, etc.) that place a particular risk of a transaction on the party that can most efficiently manage that risk. In the context of investing in a long-lived, capital-intensive power plant, the question in applying this rule is whether the owner/operator or the ratepayer is in the best (i.e., most efficient) position to manage (i.e., mitigate, hedge or insure) risks attendant to developing and operating the power plant.

Those advocating the traditional rate-regulated model believe that most risks of electric infrastructure investment are efficiently placed on ratepayers. This belief accepts that having ratepayers underwrite utility investment efficiently allocates the risks associated with that investment because by their nature those risks are most efficiently distributed widely among all ratepayers. Under this paradigm, to protect ratepayers from monopoly rents, the public utility's allowed return on equity in rate base is established by the regulator.

The *Hope/Bluefield* doctrine is a well-established utility ratemaking standard that states in part (emphasis added):

*...a public utility is entitled to such rates as will permit it to earn a return on the value of the property...to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties.*⁴³

In setting allowed return on equity, regulatory proceedings will estimate the utility's cost of equity using methods like discounted cash flow, capital asset pricing or risk premium models. In these proceedings, the regulator is tasked with setting a reasonable risk-adjusted allowed return on capital investment for the utility, understanding that much of the risk has been shifted to the ratepayer.

Conversely, under the market model merchant power developers compete for uncapped returns that they can realize through their performance in a market like PJM's.⁴⁴ While the merchant's return on its invested equity is uncapped, it also is more variable and uncertain than regulated returns. Along with this uncertainty, merchants shoulder the risks associated with the plant's operation and its viability in the face of a changing competitive fleet, technological advancement, changing rates of load growth and dynamic fuel prices.

The same risks associated with developing and operating a power plant exist in both merchant and regulated paradigms. In order to understand whether competitive markets or regulators allocate and price this risk more efficiently, it helps to start with a simplified understanding of the sources and attributes of investment capital.

Methodology

This analysis estimates a firm's cost of equity capital using the seminal CAPM first developed by Sharpe (1964)⁴⁵ and the multifactor models that were formulated later by Fama and French (1995) and Carhart (1997)⁴⁶ to incorporate effects

⁴³ *Bluefield Water Works and Improvement Company vs. Public Service Commission*, 262 U.S. 679 at 692-93 (1923) ("*Bluefield*"). See also, *Federal Power Commission vs. Hope Natural Gas Company*, 320 U.S. 591 (1944) ("*Hope*").

⁴⁴ Practically speaking, hypothetical returns in competitive power markets are not absolutely uncapped. All such markets in the United States, including PJM's, set system offer caps in both capacity and energy markets that serve as a check against wild price excursions and the potential exercise of aggregate market power among suppliers.

⁴⁵ William F. Sharpe (1964) Capital asset prices: a theory of market equilibrium under conditions of risk," *Journal of Finance* 19, 425-442.

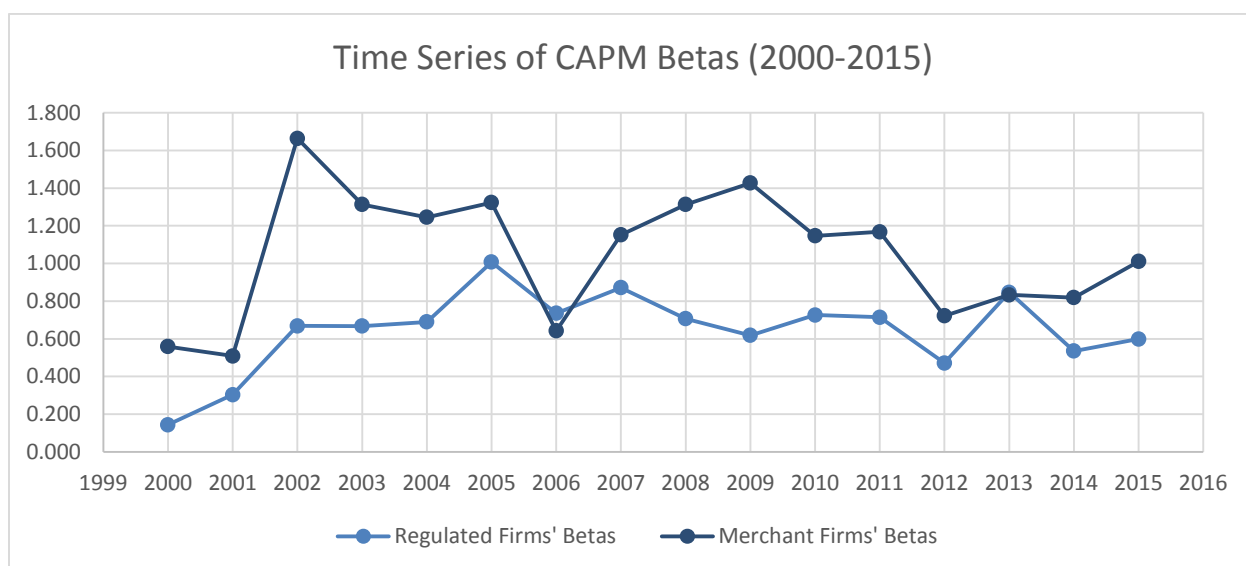
related to firm size, relative valuation and momentum. A more detailed explanation of the methodology and data sources can be found in Appendix A.

The results were the alphas and betas of the CAPM (and for the multifactor Fama-French plus Momentum model as a robustness check) for each of the nine publicly traded merchant firms and 22 regulated firms. The firms used are listed in Appendix A.

CAPM Results

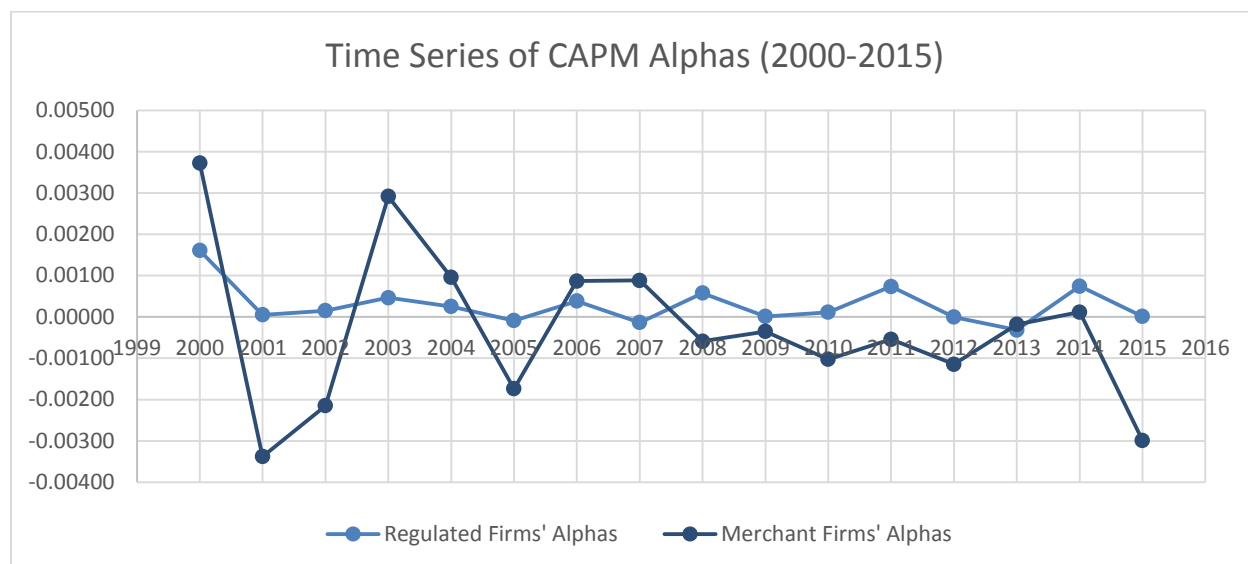
The main results based on the simple CAPM are summarized in the following two time-series graphs of historical beta and alpha (Figure 3 and Figure 4).

Figure 3. Average Annual Estimates of Beta for Merchant and Regulated Firms



⁴⁶ Eugene F. Fama and Kenneth R. French (1995) "Size and Book-to-Market Factors in Earnings and Returns," *Journal of Finance* 50, pp. 131-155; and Mark M. Carhart (1997) "On Persistence in Mutual Fund Performance," *Journal of Finance* 52, 57-82.

Figure 4. Average Annual Estimates of Alpha for Merchant and Regulated Firms



The above two graphs show the annual average beta and alpha estimates for the regulated and merchant firms during 2000-2015. Each year, the beta estimates for every firm in the two groups are averaged on an equally weighted basis to obtain annual values of risk (beta) and risk-adjusted “excess” returns (alpha).

A review of these two graphs reveals four key findings related to the CAPM analysis.

1. Average merchant betas are significantly higher than average regulated CAPM betas (1.062 versus 0.642, or 65 percent higher). Average merchant betas based on the Fama-French plus Momentum model also are higher but to a lesser degree (1.081 versus 0.778, or 39 percent larger). There is evidence that the historical betas are mean-reverting, but, even after accounting for a Bloomberg-type adjustment for this effect, a forward-looking estimate of beta based on the most recent 2015 data yields a forecast of 1.027 for average merchant firm beta and 0.751 for average regulated firm beta (still 37 percent higher).⁴⁷
2. Merchant betas seem to converge to regulated betas in better economic conditions (e.g., 2005-2006, 2012-2013) and diverge from the regulated betas in weaker economic times (2002, 2008-2009, 2015). This effect could be consistent with the notion that merchant firms face greater risk during weak economic situations but face risks similar to regulated companies when the economy is doing well. Thus, there is an asymmetry in how investors react to the riskiness of merchant firms (versus regulated firms) during times of economic weakness.
3. Merchant alphas are much more volatile than regulated alphas. On average, merchant alphas are negative but not significantly different from zero (at -4.1 bps per day) while regulated alphas are much steadier and significantly positive (+2.9 bps per day). This 7.0 bps per day difference is statistically and economically significant (with a t-statistic of 7.0 and a p-value less than 0.0001). The alpha results suggest that merchant firms are generating returns equal to their expected returns, and thus alpha is not different from zero. However, regulated firms are generating positive alphas each year and indicate that they are providing returns *in excess* of their required returns. Put another way, one can interpret the positive and significant alphas as an indication that

⁴⁷ Bloomberg data services computes an “adjusted beta” to account for possible “mean reversion” in beta estimates. The equation adjusts the beta estimated on historical data via the following equation: adjusted beta = 0.35 + 0.67 * historical beta. In the current context, one can estimate an historical beta, using daily data for 2015, and then adjust this historical beta using the above equation to generate a more forward-looking estimate of a firm’s beta.

their required returns do not adequately reflect the risks these firms face whereas the merchant firms' results suggest that risk is priced more accurately. In effect, investors in regulated firms are receiving a "free lunch" while investors in merchant companies are receiving a "fairly priced lunch." The above analysis cannot identify why there is a distortion in the way the market prices the risks of regulated versus merchant firms, but it clearly documents that there is a significant difference, which benefits investors in regulated firms' equity.

4. Based on the CAPM analysis, Table 5 through Table 7 below shows the estimated cost of equity for regulated utilities and merchant generators. The average beta for each group was taken from the above analysis, which is based on nine merchant firms and 22 regulated firms during 2000-2015. The resulting cost of equity is calculated according to the CAPM formula: the risk-free rate plus beta times the market equity premium. For the risk-free rate, the long-term 1926-2015 average of one-month U.S. treasury bill rates was employed (3.37 percent). The market risk premium of 6.36 percent is based on an estimate reported in Mehra and Prescott (2008) using long-term average U.S. stock return data from 1889-2005.⁴⁸

Table 5. Simple Capital Asset Pricing Model Cost of Equity Estimates, Historical Beta

	Risk-Free Rate	Market Risk Premium	Historical Beta	Implied CAPM Cost of Equity
Merchant	3.37%	6.36%	1.062	10.13%
Regulated	3.37%	6.36%	0.642	7.45%

Table 6. Simple Capital Asset Pricing Model Cost of Equity Estimates, Adjusted Beta

	Risk-Free Rate	Market Risk Premium	Adjusted Beta	Implied CAPM Cost of Equity
Merchant	3.37%	6.36%	1.027	9.90%
Regulated	3.37%	6.36%	0.751	8.15%

Table 7. Fama-French Plus Momentum Cost of Equity Estimates

	Risk-Free Rate	Market Risk Premium	Beta	Implied Cost of Equity
Merchant	3.37%	6.36%	1.081	10.24%
Regulated	3.37%	6.36%	0.777	8.31%

The results show the estimated cost of equity for regulated firms is 268 basis points lower than for merchant firms under the simple CAPM using historical betas, 175 basis points lower under the simple CAPM using adjusted betas, and 193 basis points lower under the Fama-French plus Momentum model. Those substantial differences in estimated cost of equity are entirely expected, given the different risk profiles of the two types of firms.

⁴⁸ Rajnish Mehra and Edward C. Prescott (2008) "The Equity Premium: ABCs." *Handbook of the Equity Risk Premium*. (Elsevier, North-Holland: Amsterdam and Boston) 1-36.

However, the 9.78 percent average allowed return on equity on rate base in recent rate cases⁴⁹ is incongruous with the above results. Under the *Hope/Bluefield* standard, the allowed ROE on rate base for a regulated utility should be equivalent to the cost of equity for the utility and reflect returns realized by other business undertakings which are “attended by corresponding risks and uncertainties.”⁵⁰ Therefore, based on the above results, average allowed return on equity on rate base for a regulated utility should range somewhere between 7.45 percent and 8.31 percent. The 9.78 percent average allowed return on equity on rate base in recent rate cases is 147 basis points above that range. In short, the consistently positive alphas suggest strongly that the utilities were overearning during that period. In contrast, the alphas of merchant firms over that period were not significantly different from zero.

Analyzing Options Offers Additional Support to PJM's Findings

Practitioners and academics typically examine both beta and option volatility to assess a stock's riskiness. Therefore, as a check on the foregoing beta results, PJM examined options pricing data based on currently traded options on five merchant firms and 15 regulated firms.⁵¹ This approach offers another way to assess the relative riskiness of these two groups as measured by the standard deviation, or volatility, of annualized returns. PJM extracted from the options data the implied volatilities for these firms as well as the historical estimates of these volatilities based on 30, 60, and 90-day histories of stock returns. This approach offered the advantage of not requiring the use of an asset pricing model, like the CAPM, and was thus simpler to compute. As noted earlier, this volatility measure captures a stock's total risk, which includes both systematic risk relative to the overall market and “idiosyncratic” or firm-specific risk that in theory can be diversified away.

In addition to the historical volatilities presented later based on past stock return data, options data can provide a forward-looking view of what investors think the riskiness of a firm's stock will be in the future. Therefore, the “implied” volatility, reported in Appendix A, uses option pricing theory first developed by Black and Scholes (1973) to extract from options prices what investors expect a stock's volatility will be over the life of an option.⁵² PJM collected these data from Bloomberg for call options closest to the stock prices of their respective stocks that have two-to-four month maturities.⁵³

The implied and historical volatilities for merchant firms range from 2.8 and 3.9 times larger than the volatilities of regulated firms' options. This confirms the earlier beta analysis which showed that merchant firms are perceived as much riskier than regulated firms. Thus, one would expect merchant firms to earn a much higher level of return than the firms that are more tightly regulated. However, the opposite seems to be true as the consistently positive alphas for regulated firms indicates these companies are earning returns higher than what they would be expected to earn given their much lower level of risk.

Conclusion: What Does CAPM and Options Analysis Say About the Relative Pricing of Risk?

The results of the foregoing examination of investment risk and how equity and options markets price this risk must be considered with caution. Comparing stock price volatility between publicly traded regulated utilities and merchant generators serves only as a proxy representation – and one with important limitations – for the different risk profiles facing

⁴⁹ The average allowed return on equity of 9.78 percent was derived from 2014-2015 rate cases for 34 electric utilities as reported in November 2015 by Public Utilities Fortnightly. See https://www.fortnightly.com/sites/default/files/article_uploads/1511-CW-2015-Rate-Cases-fig-1.pdf. This sample of 34 utilities is not the same sample of utilities used in the CAPM analysis above. Therefore, the 9.78% average allowed return on equity should be viewed as indicative only.

⁵⁰ See, note 43 *supra*.

⁵¹ The specific firms are identified in Appendix A.

⁵² Fischer Black and Myron Scholes (1973) “The Pricing of Options and Corporate Liabilities,” *Journal of Political Economy* 81, 637-659.

⁵³ These options are typically referred to as “at the money” options and usually are the most actively traded options for a stock.

a generation investor in a merchant environment and one in a regulated environment. One such limitation is that stock prices move for many reasons. For example, the market's assessment of the capability of one firm's management relative to another's will contribute to the behavior of each firm's stock price. Importantly, there are no stocks that track just merchant generation to compare with ones tracking just regulated generation. Stock prices reflect the total business of the public company, and public companies can be comprised of several diverse business lines. While this point was considered in selecting the regulated comparator companies, these regulated utilities also are engaged in transmission, distribution and retail electricity businesses in addition to owning and operating generation. Whether these added businesses (beyond generation) calm or contribute to volatility of the regulated utilities' stocks can be debated. Finally, the data sample for merchant companies is small and, as described immediately below, considerable new generation investment is coming into PJM from private developers and not publicly traded merchants.

Even taking into account the foregoing limitations, the significant variances in beta and alpha between regulated and merchant firms (further supported by the analysis examining implied and historical option volatilities) cannot be summarily dismissed. While this work does not prove that regulators are over-compensating for the risks borne by utility investors building generation under cost of service, the analysis is sufficiently compelling to raise that possibility and to warrant further inquiry. Moreover, when revisiting the notional costs comparisons of combined-cycle investment in PJM, Virginia and Florida in light of these findings, it does appear that once risk is valued, consumers of merchant generation in PJM are obtaining electricity on highly favorable terms.

Recent Actual New Investment in PJM

To the extent regulators are valuing the risks attendant to generation investment differently than organized electricity markets like PJM's, the question is: who is getting it right? One possibility is that organized electricity markets are failing to offer sufficient revenue to compensate merchant investors adequately for the risks they assume. This is a fair question to ask, given that PJM's markets are not typical ones where price formation is simply a function of supply and demand.

Actual evidence shows that PJM has successfully attracted significant new merchant investment in generating plants, both new entry and upgrade to existing facilities, during the time it has operated a forward capacity market. Public information available on financings established to support investment in PJM in the last several years suggests that banks and other lenders have evolved innovative structures particularly responsive to PJM's capacity and energy market designs. Debt and equity capital is being attracted to these structures, which are successfully closing and leading to new merchant combined-cycle investment.⁵⁴ Below are ten leading examples in PJM of these merchant-structured financings:

- Panda Power – new 829 MW Liberty Station (purchased from Moxie Energy) in Bradford County, Pennsylvania.
- Panda Power – new 1124 MW Hummel Station in Snyder County, Pennsylvania.
- Panda Power – new 778 MW Stonewall Station in Loudon County, Virginia.
- Panda Power – new 829 MW Patriot Station in Lycoming County, Pennsylvania.
- CPV – new 700 MW Woodbridge Energy Center in Woodbridge, Virginia.
- Calpine – new 309 MW Garrison Energy Center in Dover, Delaware.

⁵⁴ Despite claims to the contrary, actual evidence of new combined-cycle investment in PJM shows that the overwhelming majority of this investment is merchant in character and not plants supported by rate base, municipal bonds or long-term generation and transmission cooperative contracts with distribution cooperatives. See "New Generation in the PJM Capacity Market" (2016) by Monitoring Analytics, online at http://www.monitoringanalytics.com/reports/Reports/2016/New_Generation_in_the_PJM_Capacity_Market_20160504.pdf

- Oregon Energy Center – new 799 MW facility in Oregon, Ohio.
- Lordstown Energy Center – new 949 MW facility in Lordstown, Ohio.
- Middletown Energy Center – new 475 MW facility in Middletown, Ohio.
- St. Joseph Energy Center – new 700 MW facility in New Carlisle, Indiana.

This list is by no means exhaustive. For the years 2010-2015, approximately 134,000 MW of proposed natural gas generation entered the PJM queue. There now are approximately 74,000 MW in active development, 19,500 MW in service, 3,500 MW in partial service and 35,000 MW under construction.

Given the level of capital being attracted to PJM, it seems highly implausible to claim the market is not compensating merchant investors enough for risks they assume.

Markets like PJM's Provide Tools for Investors to Manage Risk

Why might risk-adjusted returns realized by merchant investors be lower than risk-adjusted returns paid to the regulated investor? The discrepancies shown above in comparing CAPM metrics might be attributed to regulators overcompensating regulated firms for the risks they assume. Persistent mispricing of the risk assumed by the regulated investor may occur because regulators undervalue the certainty to the investor of a fixed return over the full life of the asset, regardless of what that actual level might be. There is tremendous value to the investor in having a fixed and certain revenue stream over the life of the investment – a value that is only increased in times when the industry is facing unprecedented uncertainty, as many claim it is today.

It is also possible that allowing investment capital to compete for projects results in merchant investors accepting lower risk-adjusted returns in PJM. But it might be the case that the overall cost of this risk is reduced by allocating it properly to parties best positioned to manage and reduce this risk. To consider this third possibility, start with the following first order principal: markets place risks associated with an investment on the asset investor to manage and not on the consumer – who is in no position to manage these risks. Born from this allocation are secondary markets for risk that offer physical and financial risk management tools allowing the transparent transfer of risk, at least cost, to the party best able to manage it.

A risk management “ecosystem” has evolved to assist investors in managing investment risks by providing further avenues to lay off risk where the price to the investor in doing so is attractive as opposed to continuing to hold the risk. Through these tools, various risks (such fuel price, interest rates, operating risks, electricity prices, etc.) can be housed (for a price) with firms whose business design or position in the market allows them to manage a particular risk more efficiently than the asset owner and operator could do itself. Such firms include insurers, banks, trading firms, swap dealers, lenders and other market participants. Notably, these actors and activity while prevalent in market environments with merchant investors⁵⁵ are much less evident in regulated environments where risk management tools are largely superseded by a structure that allocates most investment risk to the aggregate consumer base.⁵⁶

⁵⁵ In the PJM footprint, investor classes participating in merchant generation investment include private equity funds, project developers, investment funds, underwriters/financiers, and merchant lenders. See, Bessemer and Shields (2015) *Resource Investment in the Golden Age of Energy Finance*, pps 10-11 http://www.isorto.org/Documents/Report/201505_IRCResourceInvestmentReport.pdf.

⁵⁶ It is thus not surprising to find exchange traded electricity futures contracts offered at liquid hubs in organized markets but not at points in non-market areas. Necessity being the mother of invention, where risks do not need to be managed, risk management tools are not created. See, e.g., NYMEX Electricity Contracts offered for PJM and MISO points, online: <http://www.cmegroup.com/trading/energy/#electricity>; and Nodal Exchange “offer(ing) futures contracts for

In PJM, the following general classifications can be used to describe the types of hedging/risk management opportunities made available to the merchant investor:

- Market design that prices risk and creates instruments to manage risk
- Structured financing models that have evolved to facilitate capital formation specific to PJM's markets
- Secondary markets to hedge price risk

Despite PJM's markets and secondary supporting markets evolving tools to assist merchant investors in managing the risks associated with their generation investment, markets for certain important risks have not yet developed sufficiently and thus merchants face some key risks that cannot be managed effectively by the existing suite of hedging instruments. These deficiencies are significant and challenge the ability for PJM and merchants investing capital in PJM to realize fully the efficiency proposition that comes from allocating investment risk to merchants and away from consumers.

PJM Market Design

PJM's energy market prices electricity nodally. Where conditions (described by system operators as "constraints") prevent the transmission system from delivering the next most economic generation to particular load, PJM will dispatch more expensive generation (described as "out of merit order" dispatch) to serve load without creating flow that would additionally burden the constraint. When this happens, electricity prices will deviate in PJM with lower prices forming on one side of the constraint and higher prices on the other side. Locationally-priced electricity, typically by node as in PJM or by zone, is a basic characteristic of organized wholesale electricity markets. The locational aspect of energy market design has been borrowed, with some modification in PJM, to differentiate between the price of capacity in one location compared to another.

Price differentiation of capacity works to signal investment in regions that would benefit most from new investment. Higher pricing to favor investment in areas where that investment offers PJM, as system operator and reliability coordinator, a greater value, optimizes the value of the transmission system as a delivery network. Without explicit and transparent pricing of locational value, generation that is cost-comparable in all other respects can end up being more expensive once the costs of transmission expansion that could otherwise have been avoided or forestalled is taken into account. Imposing explicit costs on generators for needed network upgrades to enable the resource to interconnect as deliverable capacity, coupled with the market premiums generators can realize for locating new generation in capacity-constrained areas, offers a superior approach to getting generation in the right place at the right price. PJM's market design prices the risk of poorly located investment and places this risk on merchant investors to manage.

Structured Financing Models

In a recent study commissioned by the ISO/RTO Council⁵⁷, the authors reported strong availability of low-cost financing for new merchant facilities,⁵⁸ including Term Loan B financing. Project developers typically obtain debt financing through the

on-peak and off-peak power at commercially significant hubs, zones, and nodes in the following electric markets: ISO-NE, NYISO, PJM, MISO, ERCOT, CAISO and SPP.", on line at: <http://www.nodalexchange.com/products-services/contracts/>

⁵⁷ Bessemer and Shields (2015), note 55, *supra*.

⁵⁸ *Id.* at p. 13 ("Anecdotally, debt financing deals that were being done 3-4 years ago at LIBOR plus 700 -900 basis points (bps), are now being done at LIBOR plus 300-400 bps. Project debt-equity ratios have also been increasing from around 1:1, to closer to 2:1.").

Term Loan A, or senior term loan, market. Term Loan A financing comes with significant covenants, including (1) the requirement that almost all price exposure be hedged out five to seven years, which is a typical holding period of the asset for a developer and (2) substantial amortization, or repayment of principal, over the loan period. In contrast, Term Loan B financing has fewer restrictive covenants, with less rigorous hedging requirements but higher interest rates.⁵⁹ The study authors also reported strong investor interest in the PJM footprint.⁶⁰

For project developers, uncertainty over electricity and fuel prices is the primary source of cash flow uncertainty, and lender requirements are a primary driver of hedging programs and financial derivative structures for new generating facilities.⁶¹ For example, funding the construction of a merchant combined-cycle facility requires large sums on the order of \$1,000/kW, financed in part by debt. Lenders, especially lenders of Term Loan A financing, often will require that the generating facility be hedged as long as possible, currently about five to seven, and the less effective the hedge, the more expensive the terms. Those hedges have three common structures: (1) physical tolling arrangements, (2) heat-rate call options and (3) revenue puts.

A natural gas generating facility is a physical conversion option, which gives the holder the option to convert natural gas to electricity when profitable – when the spark spread⁶² exceeds the cost of generation, based on commodity prices and the facility's heat rate.⁶³ Liquid natural gas and electricity pricing hubs, like those in the PJM footprint, allow for physical tolling, which acts as a hedge for earnings and can facilitate financing for the construction of a natural-gas generating facility.

Under a typical tolling agreement, a marketer pays the owner of a generating facility a fee to “rent” the facility. The tolling fee typically has two parts: a fixed monthly capacity payment and a variable tolling charge for each megawatt-hour of electricity produced by the facility. The facility owner uses the fee to pay its lenders and provide an equity return. The fixed monthly capacity payment can be tied to the capital loan payments, eliminating default risk and facilitating debt financing. The marketer is responsible for the natural gas deliveries and electricity sales and generally takes the full commodity price risk in return for upside profit potential from forward and reverse tolling.⁶⁴

A heat-rate call option entitles the holder of the option to purchase power at a strike price that is based on an indexed gas price multiplied by the generating facility's heat rate. Under a typical structure, the holder of the heat-rate call option captures the intrinsic value of a below-market heat rate and, in exchange, pays the facility owner a monthly capacity

⁵⁹ *Id.* at pp. 13-14.

⁶⁰ *Id.* at p. 17 (“PJM was seen as rebounding from a demand trough, and consequently seeing strong investment.”).

⁶¹ For merchant projects, sufficient cash flow is needed to cover debt service and, it is hoped, earn an equity return. Going forward, it is unclear whether merchants and lenders will have the tolerance to take on risky investments in large base-load generating facilities. At the same time, it is unclear to the extent that those large, risky investments will be needed. Technology breakthroughs -- in energy storage, grid management, distributed solar and others -- may dramatically transform base-load needs within the useful lives of generating facilities built today.

⁶² Spark spread is the price difference in equivalent units between the market price of electricity and the market price of fuel at the same or nearby locations and for the same delivery period.

⁶³ Heat rate is a widely used measure of thermal efficiency that is used to compare natural gas and electric power quantities and prices in equivalent terms. Operating heat rate is a measure of the operating efficiency of a generating facility, expressed as the number of megawatt-hours of electricity expected from a given amount of natural gas in British thermal units (Btu). Economic heat rate, which typically is higher than the operating heat rate and is used to price transactions or establish contractual obligations, may include costs other than fuel costs, such as variable operating and maintenance costs, startup costs and ramping costs.

⁶⁴ A positive spark spread, based on the generating facility's economic heat rate, would indicate that it is more economical to burn natural gas to generate electricity than to purchase electricity from the grid, i.e., a forward toll. A negative spark spread would indicate that it is more economical to sell the natural gas in the spot market and purchase electricity from the grid, i.e., a reverse toll.

payment. As with a tolling arrangement, the monthly capacity payment can be tied to the capital loan payments, eliminating default risk and facilitating debt financing.

Based on recent interviews with merchant developers, revenue put options (or simply revenue puts) have emerged as the prevalent hedge structure for recent greenfield projects. Revenue puts establish a revenue floor for a generating facility that helps to stabilize earnings and ensure debt coverage. One developer characterized a revenue put as “debt market demand for debt service coverage protection,” whereby, at financial close, the developer pays the revenue put provider to ensure that debt service will be met for the duration of the hedge.⁶⁵ For example, for an 800 MW plant with a total development cost of approximately \$850 million, the developer will pay approximately \$30 million-\$40 million to a financial entity for a revenue put. Under the revenue put, the financial entity will ensure the debt holders that their debt will be serviced for the term of the hedge, currently about five to seven years. In all three of the above hedge structures, Financial Transmission Rights (FTRs) and over-the-counter basis swaps can reduce the risk of price differentials between a generating facility node and a liquid pricing hub.⁶⁶

Secondary Markets

Moreover, those making investments in generation in PJM can turn to instruments made available in secondary markets to manage these risks. Certain of these markets offer generic hedging instruments that can be used to manage fuel price risk. Other markets offer instruments specifically designed to PJM's markets and allow parties the opportunity to hedge electricity risks and to manage these risks using a variety of means: FTR markets, bilateral trades financially settled, physical trades and cleared trades on NYMEX,⁶⁷ ICE,⁶⁸ Nodal Exchange⁶⁹ or other platforms. In general, organized electricity market regions like PJM, with liquid pricing hubs and a wide variety of financial instruments on multiple platforms, allow for clean and efficient hedges that facilitate project lending and capital investment.

Deficiencies

Lenders and merchant generation investors have developed customized financing structures to reflect the logic of PJM's market design in regards to its market prices, its allocation of risk and its evolution of tools designed to manage that risk. These structures additionally have accessed instruments offered in related secondary markets to help manage risks faced by investors in and lenders to merchant generation. While these arrangements have succeeded in forming capital to support investment in merchant generation in PJM, this success has occurred despite a potential glaring deficiency – the lack of a forward hedging instrument to lay off capacity and energy price risk over the long term.

Financing capital-intensive, long-lived merchant generation requires investors to assume natural gas price risks that can be effectively managed through exchange and bilateral markets only for perhaps five to seven years into the future. Hedging the price risk of the output – capacity and energy – poses an even bigger challenge for the merchant generator. PJM's capacity market is described as a forward market. Auctions for capacity occur three years prior to the delivery year.

⁶⁵ Confidential interview on December 28, 2015.

⁶⁶ For example, the PJM Western Hub for electricity or the TETCO-M3 hub for natural gas.

⁶⁷ In 2003, NYMEX began offering financially-settled electricity futures with final settlement on real-time PJM Western Hub prices. These NYMEX futures contracts were the first with ISO/RTO-price final settlement. The PJM Western Hub now may be the most liquid electricity futures market in the world with trade multiples of over 4.7 in 2013. See Bessemer and Shields at p. 25.

⁶⁸ Intercontinental Exchange, or “ICE,” is a major execution venue for over-the-counter trading in prompt and day-ahead markets for North American power.

⁶⁹ Nodal Exchange offers on-peak and off-peak day-ahead and real time contracts settled at LMP for monthly terms with expiries of up to a forward 68 months, at commercially significant hubs, zones and nodes in organized electric markets including the PJM markets. Nodal Exchange offers contracts on a wider set of locations than NYMEX and ICE and provides price signals at each nodal location. Nodal Exchange also offers “energy plus congestion” futures contracts for basis risk management.

But, PJM's capacity auctions provide only year-by-year certainty – as opposed to fixing price certainty over a strip of years. It was anticipated that price variability in PJM's auctions would spur buyers (load) and sellers (generation) to come together bilaterally in secondary markets to contract for the purchase and sale of capacity at a fixed price over a longer term. Evidence suggests that buyers and sellers are hedging their respective capacity price risks through bilateral contract in reasonably small volumes. Indeed, it appears buyers and sellers of capacity remain largely exposed to spot price outcomes.

Several factors may explain the reluctance to fix prices bilaterally. First, PJM's capacity market is relatively young, and it has required changes that have made it difficult to predict future prices based on historic outcomes, noting further that historic outcomes have demonstrated significant volatility. Second, retail choice regimes in several PJM states deter competitive retail providers from long-term wholesale contracting because end-use customers under such regimes typically are committed to six-month or one-year contracts with their suppliers. Third is the mandatory nature of PJM's capacity market, whereby all capacity must be transacted through the three-year forward auction or in any one of three incremental auctions before the start of the delivery year. However, perhaps the biggest and most obvious explanation is that the bid-ask spread, the difference between what buyers are willing to pay and what suppliers are willing to receive, for bilateral contracts is simply too large a gap to overcome.⁷⁰

Conclusion: Findings Regarding Resource Entry in Markets

Having examined the goal of appropriate resource entry from several different vantages, the data show that markets are fulfilling their objective of motivating appropriate resource entry into the overall generation portfolio, and doing so in a cost-effective manner for the consumer. The results show:

- PJM offers a neutral, transparent proving ground for any project or technology to demonstrate its value based on its merits. High-capital, high-risk projects do not find footing, while lower-capital, lower-risk projects can flourish (if appropriate) without being impeded by a closed regulatory construct.
- PJM and regulatory regimes both are bringing new combined-cycle entry online at comparable costs (leaving aside the cost of risk).
- Once risk is examined, financial models show that, while the actual returns are appropriate for merchant generation given risk, the returns for regulated generation companies are notably higher than the models would predict given the lower risks they face.
- The abundance of merchant projects coming online in PJM indicates that the market is providing adequate returns to attract capital.
- Discrepancies in risk-adjusted returns between merchant and regulated investments may reflect regulators mispricing risk; and/or may result from capital competing for projects through use of both efficient financing structures and risk-management tools that serve to lower the cost of risk and returns.
- The PJM markets could see further cost efficiency from merchant entry if longer-dated risk management instruments were available.

⁷⁰ See Pfeifenberger, Johannes, Newll, Samuel, Spees, Katheleen, Hajos, Attila, and Madjarov, Kamen ("The Brattle Group"), Second Performance Assessment of PJM's Reliability Pricing Model Market: Results 2007/08 through 2014/15, prepared for PJM Interconnection, LLC, August 26, 2011. Online at http://www.brattle.com/system/publications/pdfs/000/004/833/original/Second_Performance_Assessment_of_PJM's_Reliability_Pricing_Model_Pfeifenberger_et_al_Aug_26_2011.pdf?1378772133. The discussion on long-term contracting starts at p. 57 of the report. The authors note, "Suppliers of existing capacity are unwilling to enter long-term contracts at low current prices because they expect prices will rise. At the same time, buyers are unwilling to pay higher prices or even the cost of new generation when there are less expensive options currently available in the market." At p. 58.

Resource Exit: An Empirical Examination in Regulated and Market Environments

To test the theoretical hypotheses described earlier in this paper associated with resource exit, PJM examined the retirement of coal plants in PJM as compared to retirements in two different types of areas:

- areas of the country where organized markets do not operate
- in these same areas, but also including areas where organized markets optimize a given fleet of generating resources but rely largely on state regulation to dictate the entry and exit of these resources

The empirical data needed to contrast decision outcomes in markets and regulated constructs requires comparing generation units having similar attributes but located in different environments (market or regulated) with each facing the same type of investment decisions. With only 20 years of competitive wholesale market experience to work with, such cases are relatively few; however, changes in environmental policies present one such opportunity.

Mercury and Air Toxics Standards: A Recent Natural Experiment to Examine Capital Investment Decisions

In 2011 the U.S. Environmental Protection Agency issued the Mercury and Air Toxics Standards (MATS) rule mandating compliance by no later than April 2016. MATS is a command-and-control type program that requires coal and oil-fired generation sources to meet emissions-rate standards for hazardous air pollutants.⁷¹ All affected coal and oil resources, regardless of location and operating paradigm (market or regulated), must comply with MATS. Consequently, given the nature of the rule, owners of effectively all noncompliant generators must choose to make capital investments or retire the resource.

The MATS rule differs from other recent environmental policies in that compliance requires more capital investment versus increased expenses or reduced operations. MATS is unique in that it forces a retirement if the capital investment is not made.

Moreover, because MATS was issued four years after the implementation of the PJM Reliability Pricing Model Capacity Market, it provides a natural experiment to examine how investment and capital allocation decisions differ between regulated and competitive market paradigms with respect to investment or retirement decisions.⁷²

Empirical Test

In order to test for a difference in retirement trends between PJM and fully-regulated areas, data was collected on all coal generators in the continental United States and examined using an environmental upgrade cost model. The cost model provided a measure of the incremental cost each coal unit faced in order to continue to operate under the MATS rule. This cost figure was combined with data on exit/upgrade outcomes, and the results were analyzed to identify contrasting trends between PJM and regulated, non-PJM environments. Trends were identified using a logistic regression model. This

⁷¹ Note that the studies looking at the Title IV SO₂ Trading Program and the NO_x Budget Program must acknowledge a difference in the case of MATS, insofar as MATS is command-and-control regulation while the earlier rules created trading regimes with greater inherent flexibility. Additionally, the EPA has issued the Cross State Air Pollution Rule (CSAPR), which is a stricter extension of the EPA's Clean Air Interstate Rule for SO₂ and NO_x emissions, and the Regional Haze Rule. Many compliance options for CSAPR and the Regional Haze Rule are complimentary to MATS compliance, and this paper does not attempt to control for them in the case study.

⁷² The purpose of using MATS as a case study should not be taken as a re-examination of the MATS rule that PJM published in 2011. See PJM Interconnection, LLC, "Coal Capacity at Risk for Retirement in PJM: Potential Impacts of the Finalized EPA Cross State Air Pollution Rule and Proposed National Emissions Standards for Hazardous Air Pollutants" August 26, 2011. ("PJM MATS Analysis")

statistical technique is a method for comparing the relationship between different inputs and outcomes and can help provide a mathematical answer to questions such as “Holding all else equal, is a generator more or less likely to retire in PJM compared to other areas?”

Method

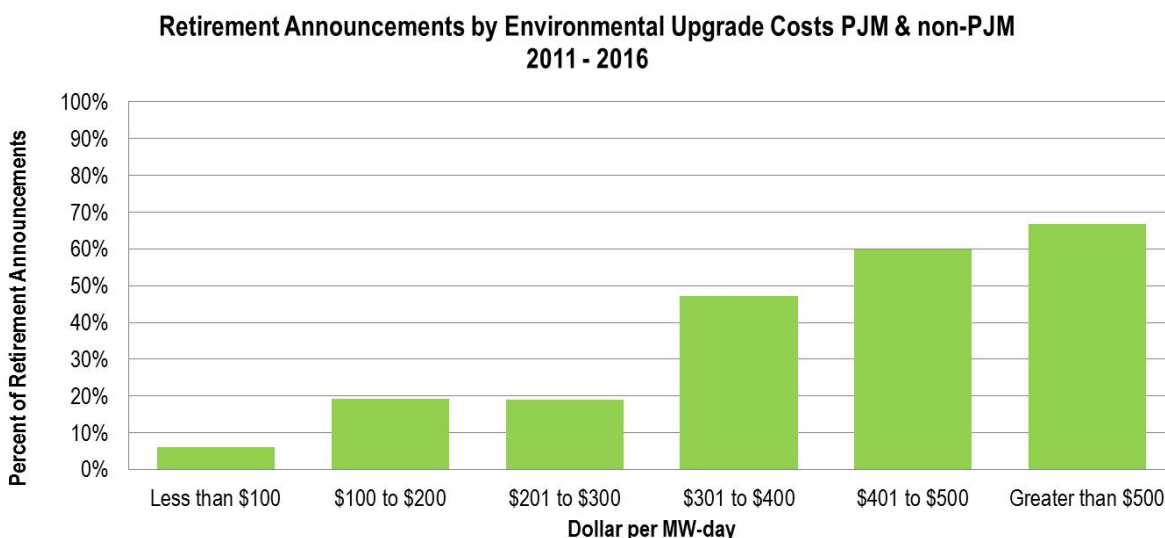
To determine the capital investment required to comply with MATS, PJM followed the methodology it used in its 2011 study on MATS⁷³. This method uses a model from Sargent and Lundy to estimate the technology and costs required for compliance according to coal unit characteristics such as emission rate, nameplate capacity and coal type. With data on the cost of coal pollution control technologies from EPA at the time MATS was issued in 2011, the total retrofit cost needed to comply with MATS can be determined.

In order to conduct a robust examination of the data, different definitions of “regulated area” were examined. Appendix B to this report thoroughly describes the methodology, these definitions and the results of the analysis. This paper will discuss the results at a very high level and, for that purpose, will characterize the results of all the different variations. But, when a specific statistic or graphic is discussed, it will refer to PJM (defined by states that are largely within the PJM footprint) as compared to regulated states (defined as a variety of non-PJM states throughout the country that use integrated resource planning rather than a capacity market construct to handle portfolio planning, some of which are within ISO/RTOs that do not use robust capacity markets).

Validation of the Model

Once the model was created, PJM examined the model to verify that it performed as expected. For example, an observer would expect that the older a generator was, the more likely it would be to retire, all else equal. As expected, the model does show that a generator is more likely to retire if it is older, has a lower capacity factor and faces substantial capital investment costs for environmental upgrades (see Figure 5 below).

Figure 5. Retirement Probability by Upgrade Cost for all Generators



⁷³ “Coal Capacity at Risk for Retirement in PJM: Potential Impacts of the Finalized EPA Cross State Air Pollution Rule and Proposed National Emissions Standards for Hazardous Air Pollutants”, (2011)

Models of this type often are used to assess the difference in probability of an event as related to another factor (such as age). However, the results also are useful in the absolute. The model shows that the probability of retirement for a mathematically average generator is very low. The probability is slightly lower in PJM, and marginally higher in regulated, non-PJM environments.

Table 8. Predicted Probability of Retirement

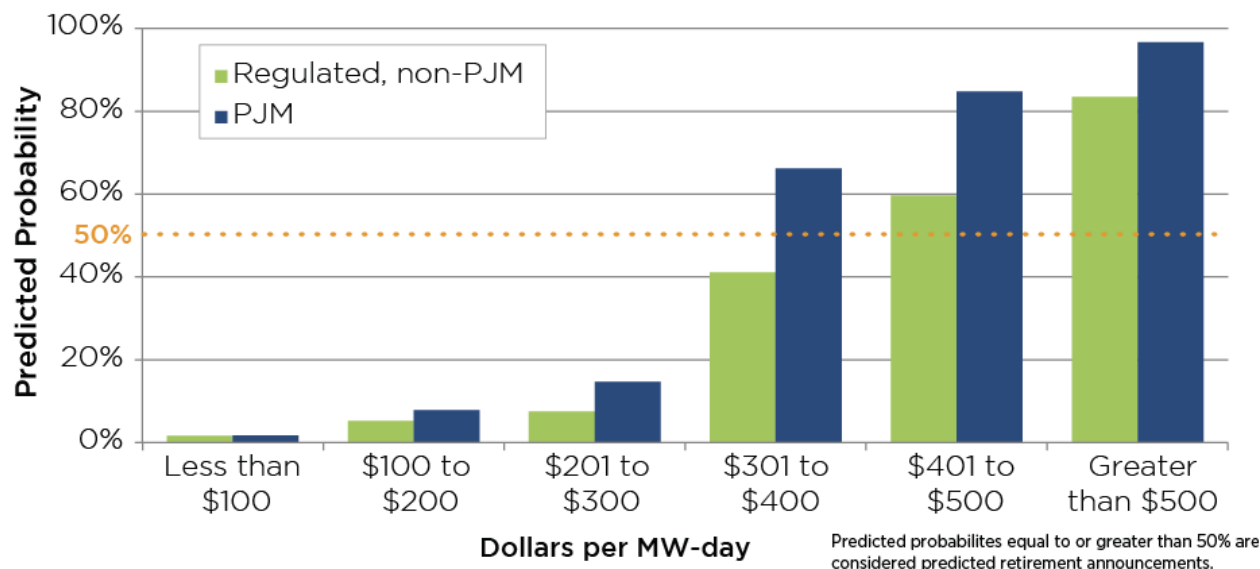
	Predicted Probability of Retirement
All Generators Studied	4.7%
PJM	0.7%
Regulated areas	8.8%

Results

Overall the model shows that the probability of the mathematically average generator retiring in PJM is lower than in the regulated environment. Under some definitions of “regulated environment,” the difference is statistically significant, and in other scenarios it is not. The conclusion is that the likelihood of a generator exiting is approximately the same in PJM as in the regulated environment.

This is not to say there are no differences at all. Certain scenarios do show notable differences in the likelihood of retirement. Figure 6 below shows the probability of retirement for generators facing different levels of environmental upgrade costs.

Figure 6. Predicted Probability of Retirement by Upgrade Cost

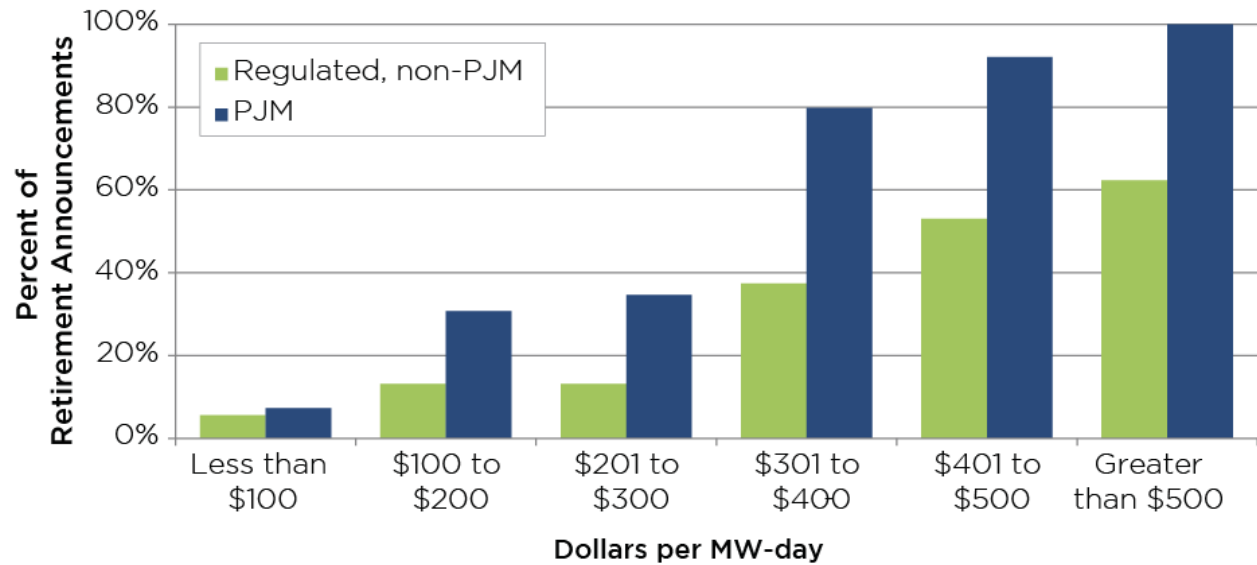


In both environments, as expected, generators facing significant upgrade costs have a higher probability of retirement. The probability is notably higher in the PJM environment. Given that the market is indifferent to the upgrade costs of a generator, this is a predictable outcome. Without greater revenues to support the generator, retirement would be a rational choice for the owner. This effect becomes more pronounced as the upgrade costs rise above the cost of new entry. In

regulated environments, where ratepayers support the upgrade (and where the utility is earning returns on capital investment), uneconomic generators are less likely to retire.

This prediction can be compared to the actual figures on announced retirements. The announced retirement figures show similar trends overall.

Figure 7. Comparison of Announced Retirements



Summary

The analysis of retirements due to MATS in PJM and in regulated areas shows no substantial difference in behavior: under both regimes, older, smaller units with relatively low capacity factors tend to retire. Likewise, generators located in both regulatory environments are more likely to retire as they face increasing upgrade costs. Under certain specifications of the model, units located within PJM tend to be more sensitive to increases in upgrade costs. This tendency becomes particularly pronounced when upgrade costs rise above the level of the cost of new entry.

For all generators, those units of average age, size, capacity factor and upgrade costs are not likely to retire. However, the average generator located within PJM is predicted to be even less likely to retire when compared to a regulated counterpart.

In general, the results show that a generator has approximately the same likelihood of retirement in PJM as in the regulated environment. The data presented here do not support the assertion that markets (compared to regulation) tend to force the retirement of generators that still have a remaining useful life.

Effectiveness of Markets in Managing the Resource Portfolio

This paper posed a significant question:

Can we rely on PJM's organized wholesale electricity market to efficiently and reliably manage the entry and exit of supply resources as external forces create tremendous uncertainty and potential industry transformation?

The sheer scope of this question precludes a definitive answer within the context of a single paper or analysis. However, this paper has examined entry and exit in both market and regulated environments and set forth strong evidence showing the effectiveness of the PJM markets in managing the entry and exit of resources in the portfolio.

Regarding entry, the findings here reflect the conclusions that the markets do well in attracting new entry at an efficient cost. Competitive forces work to lower costs and exclude technologies with inappropriately high costs. The markets are incenting new entry at competitive costs. In addition, the market environments create a paradigm in which risk is shouldered by and managed by the investor, rather than the customer. The analysis shows that the returns for merchant generation companies are appropriate given the levels of risk. Moreover, comparing risk-adjusted returns for investments in regulated environments suggests that PJM customers are realizing superior value from merchant plants supported solely by PJM market revenues.

Regarding exit, the regression model based on the MATS natural experiment shows that generator exit when facing similar investment requirements is roughly comparable in both environments. The PJM markets show no signs of inadequately compensating legacy units and forcing a premature retirement of economically viable generators.

Collectively, the analysis shows that the PJM markets are succeeding in efficiently and reliably managing entry and exit, even while adapting to changing circumstances. However this should not be taken to say that the PJM markets can continue to manage resource adequacy in a cost advantageous manner in the face of any potential change. Indeed, as addressed immediately below, regulator actions to advance other political and social interests can disrupt and even defeat altogether the advantages that organized markets can bring in managing resource entry and exit.

PART 2

Actions Taken to Further Environmental, Social and Political Interests Can Erode the Market Value Proposition

Organized Electricity Markets and Public Policy

Within PJM, resources including demand response compete on price or cost subject to reliability constraints so that the mix of resources and energy production should come from the least-cost set of resources. In this sense, the PJM markets are neutral with respect to age, technology, size and fuel type, provided resources meet performance requirement to ensure reliability.

As examined in Part 1, the PJM markets offer a more attractive environment than non-market regions for the interconnection and participation of innovative technologies. Nevertheless, from time-to-time policymakers contend that organized markets are not integrating new technologies quickly enough or are not rewarding existing technologies sufficiently for their attributes. These attributes are often associated with technologies that advance environmental policies, or other objectives beyond the lowest-cost, reliable source of electricity.

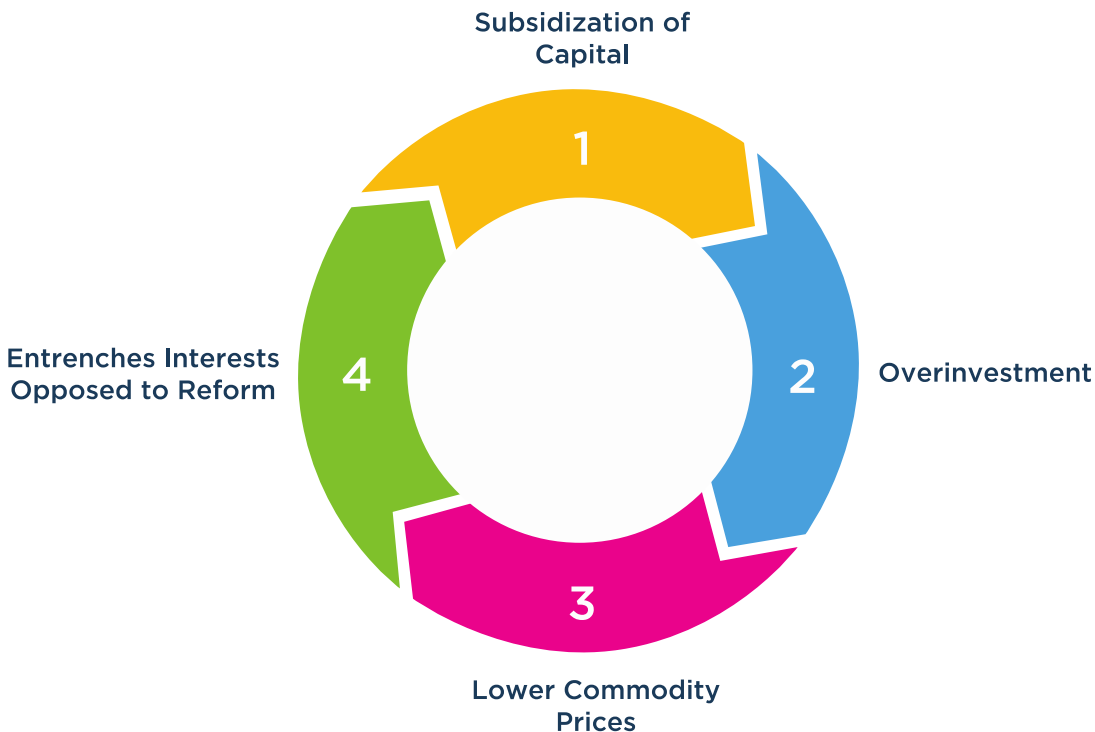
Policymakers may seek to promote or protect interests to which PJM's organized electricity markets are agnostic, including economic development, jobs, local tax base and fuel diversity. Promoting or protecting interests beyond the goal of providing reliable electricity at least cost – whether those interests are environmental, social or political – may take the form of subsidies. However, subsidies and other preferences can harm – in both theory and practice – the efficient operation of organized electricity markets to a degree that could threaten the mission of retaining only the most efficient resources needed for reliable operations and attracting new investment when economically warranted.

Explicit subsidies⁷⁴ take various forms in the electricity industry.

State & Local Government	State Public Utility Regulation		Federal Government	Federal Public Utility Regulation
Tax abatements	Net metering		Production tax credits	Full locational marginal price compensation for DR
Economic development grants	Feed-in tariffs		Tax credits	Reliability Must Run (potentially)
Tax Exempt Financing (Municipal)	Out-of-market payments	State directed contracts	DOE Loan guarantees	Reference Power & Federal Power Marketing Agencies
	Stranded cost recovery		Funded research & development	

⁷⁴ Subsidies can be viewed as a two-sided coin: explicit subsidies for politically-favored resources and implicit subsidies that excuse or fail to price external or "public" costs created by resources. "(D)efining a subsidy to include all government interventions leaves out an important category: It 'does not include the externalities associated with electricity generation'." Moot, Subsidies, *Climate Change & The FERC*, Energy L. Jour. Vol. 35, No. 2, p. 349, quoting Kitson, et al., *Subsidies and External Costs In Electric Power Generation: A Comparative Review of Estimates*, 6 Int'l Inst. for Sustainable Dev. (2011). The table above touches only generally and superficially the panorama of subsidies affecting the electricity industry. Last year, the U.S. Energy Information Administration released a nearly 70-page report detailing just direct federal subsidies affecting electricity production. *Direct Federal Financial Interventions and Subsidies in Energy in Fiscal Year 2013*, (March 2015), online at: <https://www.eia.gov/analysis/requests/subsidy/pdf/subsidy.pdf>.

In the electric industry, explicit subsidies effectively reduce the cost of capital to develop, construct or retrofit generating facilities that otherwise would be considered risky or too expensive and thereby not competitive but that are preferred because of other desired attributes as discussed above. This “capital bias” may lead to an overinvestment in generation resources with the resulting oversupply exerting downward pressure on commodity prices and reducing the financial viability of otherwise cost-effective resources. Lower prices and overinvestment sustained by subsidies may create entrenched and concentrated interests from both consumers and producers. Political interests similarly may be invested in campaigns to protect low prices or prevent the displacement of embedded capital and the resultant social and human costs, such as job losses or a diminished tax base. These interests, once entrenched, will naturally tend to resist policies removing their subsidies, and this contributes to an on-going cycle of subsidization.



Social, environmental and political interests typically justifying incentives and subsidies do not reflect competitive market principles because incentives and subsidies can create an uneven playing field among competitors and weaken the value of price signals. Those interests (e.g., jobs in local communities, industry to support tax base, the environmental advantages of renewable generation) may represent valid public policy objectives. However, organized electricity markets will not naturally advance those objectives except coincidentally to the extent they accompany the objective of least-cost, reliable electricity. Indeed, even objectives that may be considered elements of good energy policy, such as having a diverse generation portfolio or highly secure and resilient resources, will only result to the extent that organized markets ascribe value to, and pay for, those attributes. So, given the foregoing, can generation owners and local lawmakers fairly claim that PJM's markets are flawed because revenues are insufficient to cover the going-forward costs of certain legacy assets having desirable attributes? The question requires further examination.

Generally, an independent observer of a market would perceive a naturally arising commercial environment where the “invisible hand” is trusted to produce efficient price outcomes. When firms fail and invested capital is lost, the observer usually would not blame the market. To the contrary, the observer likely would view the market as pricing out inefficient resources or poorly considered or timed investments. However, organized electricity markets are less organic than most

commercial environments. They are highly designed, where price formation depends not only on the forces of supply and demand but also on a “visible hand” forging and implementing extensive rules and complex market clearing models and optimization algorithms.

Given the complex design features of organized electricity markets, it is fair to ask whether a generating facility struggling to earn sufficient revenue is coping with a valid price signal that indicates it should retire or whether instead it is impacted by a market design deficiency that could lead to premature retirement.⁷⁵ Getting prices “correct” is important especially considering that in PJM (as is true for certain other market operators) market design has been entrusted with the critical mission of ensuring adequate supply to maintain reliability. Moreover, broad economic and social harm beyond the energy markets could occur if inaccurate prices in organized electricity markets result in a suboptimal resource portfolio. Nevertheless, the simple fact that a generating facility cannot earn sufficient market revenue to cover its going-forward costs does not reasonably lead to the conclusion that wholesale markets are flawed. More likely, it demonstrates that the generating facility is uneconomic.⁷⁶

Recently, when low market revenues have jeopardized the continuing viability of a generating facility, some have charged the market with harming important local interests, noting that asset retirement will cost jobs and deprive localities of property tax revenue.⁷⁷ These dislocations indeed are real and require difficult adjustments. Accordingly, wholesale market administrators must continually ensure that the returns provided by the organized electricity markets are “correct” and that legacy assets do not face inefficient, premature retirements.⁷⁸ If lawmakers, regulators or legacy asset owners believe the market suffers from a flawed design that suppresses prices or incompletely values certain resources, they will feel pressured or obligated to advocate for out-of-market subsidies intended to attract or retain resources they believe should be better compensated.

A generation resource that is state-subsidized through an out-of-market contract still participates in PJM’s capacity market.⁷⁹ Given the comprehensive structure of the capacity market design, participation by subsidized resources will degrade price signals and potentially undermine the reliability objectives of the capacity market. Therefore, PJM has established the minimum offer price rule (MOPR) to mitigate potential harm to the capacity market from planned (new)

⁷⁵ Such “deficiencies” cannot be presumed to always suppress prices. In fact, various PJM stakeholders regularly argue that market design flaws contribute to inflated prices.

⁷⁶ In comments to the U.S. Environmental Protection Agency (EPA), the Public Utilities Commission of Ohio (PUCO) described the long-term prices signals resulting from PJM’s capacity market as designed “to allow for the continued maintenance of *all* existing generation facilities. . .”, *EPA’s Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, Comments of PUCO, p. 5 Docket No. EPA-HQ-OAR-2013-0602, (December 1, 2014) (emphasis added). The PUCO’s characterization of the PJM market omits the important qualifier that an existing generation facility should remain viable only to the extent it remains economic.

⁷⁷ See *The New York Times*, “Indian Point Owner to Close Nuclear Plant Upstate, Angering Governor,” November 3, 2015 (discussing Entergy’s decision to close the Fitzpatrick nuclear facility and reporting the impending loss of 600 high-paying jobs at a facility that pays half the property taxes collected by a local school district).

⁷⁸ The PUCO recently considered this assertion in granting a request by FirstEnergy, which owns certain legacy generating facilities that are struggling to earn revenues in the PJM markets sufficient to cover their going forward costs. FirstEnergy seeks a contractual stream of revenues sourced from ratepayers to “prevent plants from retiring before it is economic to do so.” Deposition Testimony of Larry Makovich, PUCO, Case No-14-1297-EL-SSO, p. 3 line 5.

⁷⁹ A seller has little choice but to offer a state-subsidized generation resource into the PJM capacity market because market participation (and clearing) is required for the resource to be recognized as capacity towards PJM’s resource adequacy requirement. Otherwise, if the resource is not credited as capacity, the load-serving entity will pay once for capacity under the out-of-market contract and again by operation of the PJM capacity market because PJM still must procure sufficient resources in the capacity market to meet system needs. Figures 8 and 9 below illustrate this point.

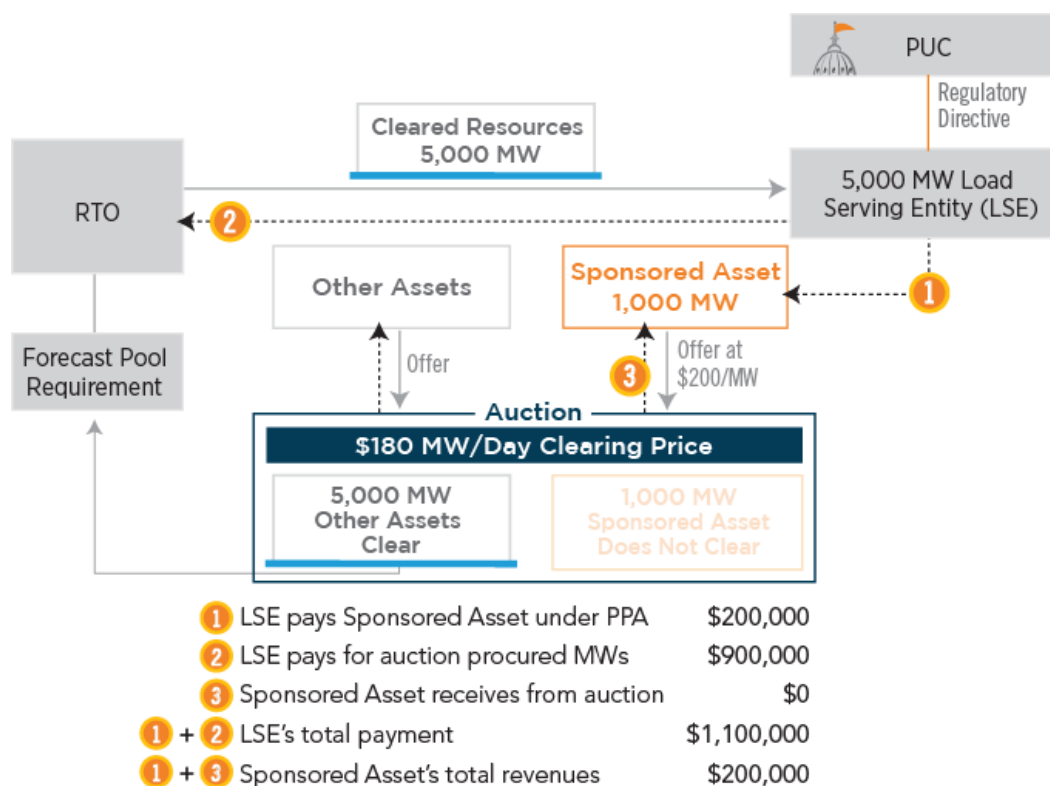
resources that received supplemental, out-of-market revenues.⁸⁰ The example below explains the need for mitigation rules.

An Example of the Need for Mitigation

Illustrated below is a simplified system showing a single load serving entity that is obligated to procure 5,000 MW of capacity to cover its load and reserves. The state public utility commission directs this LSE to enter into a contract for differences with the developer-owner of a new generating station (the “Sponsored Asset”); the LSE will pay the developer \$200/MW-day minus any revenues the developer receives from clearing the ISO/RTO capacity market. The 1,000 MW Sponsored Asset will compete with both incumbent generation and potential new entry (“Other Assets”) whose total installed capacity exceeds the 5,000 MW, which the RTO must procure to meet the LSE’s load and reserve requirements. On the one hand, the developer is indifferent to whether its asset clears the auction because its contract guarantees it will receive \$200/MW-day from the LSE regardless of the auction outcome; the LSE, on the other hand, is significantly interested in having the Sponsored Asset clear in order to reduce its contractual payments to the developer.

In Figure 8 below, the Sponsored Asset is offered into the auction at \$200/MW-day. It does not clear the auction because the auction settles at \$180/MW-day. Accordingly, the ISO/RTO charges the LSE for 5,000 MW at the auction price of \$180/MW-day. Additionally, the LSE is contractually obligated to pay the asset owner \$200/MW-day for the 1,000 MW that did not clear. In this case, the LSE pays a total of \$1,100,000 for capacity procured to meet its load and reserves.

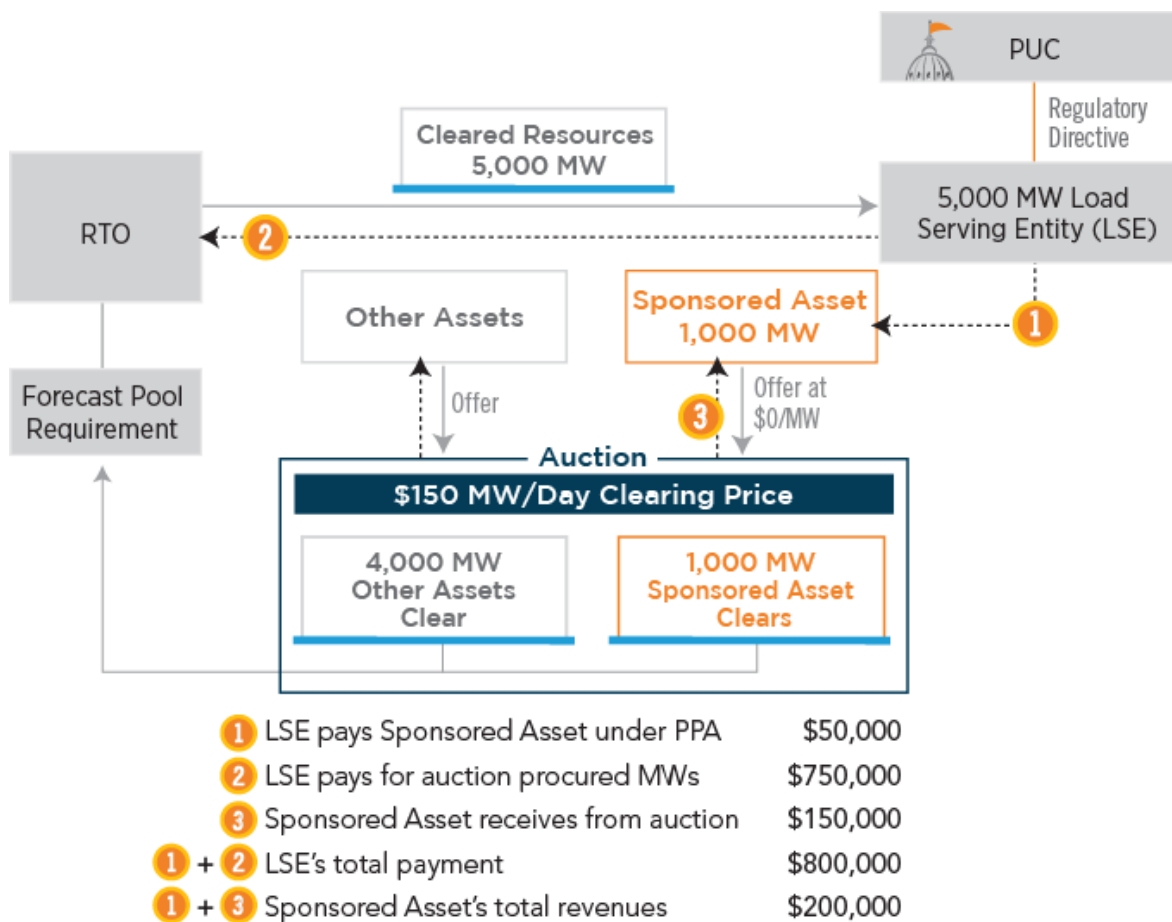
Figure 8. 1,000 MW Sponsored Asset Does Not Clear



⁸⁰ While all resources that clear a capacity auction will receive the single clearing price, the load serving entity that is party to the contract for differences is highly incented to ensure the subsidized generation resource clears (in order to avoid being charged for redundant capacity) and thus may contractually direct the seller to offer the resource into the auction at \$0/MW. PJM's MOPR prevents the seller of a new-entry resource from acting on this incentive by requiring that the seller offer the resource into the auction at a price reflecting the resource's actual costs to protect the integrity of the auction's price outcome from artificially low offers made possible by the subsidy.

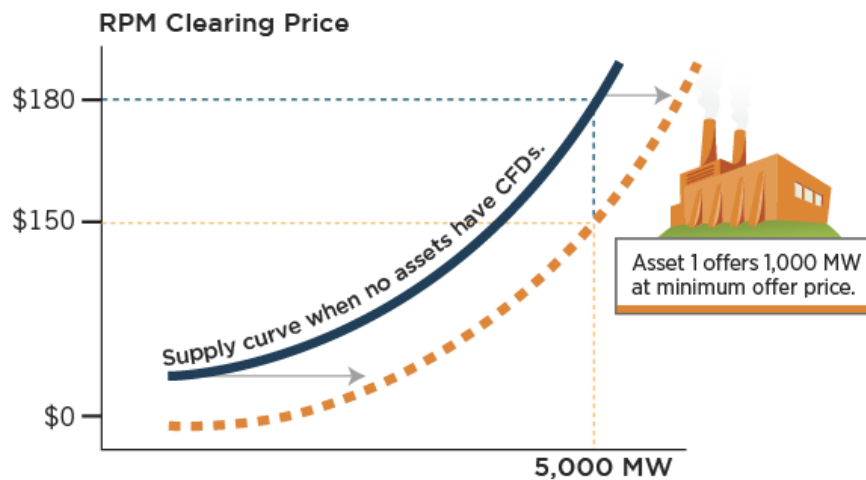
In Figure 9 below, the 1,000 MW Sponsored Asset is offered at \$0/MW-day and thus clears the auction. In so doing, it displaces 1,000 MW of Other Assets, and its \$0/MW-day offer, which is below cost, suppresses the clearing price from \$180/MW-day – had the auction cleared without the Sponsored Asset (see price in Figure 8) – to \$150/MW-day. The asset owner receives \$150/MW-day from the auction for its Sponsored Asset. The ISO/RTO charges the LSE for 5,000 MW at the auction price of \$150/MW-day. Additionally, the LSE will be contractually obligated to pay the Sponsored Asset owner \$50/MW-day (the difference between the contract price of \$200/MW-day and the auction price of \$150/MW-day) for the 1,000 MW that cleared, for a total of \$800,000.

Figure 9. Other Assets and 1,000 MW Sponsored Asset Clear



The difference between \$180/MW-day and \$150/MW-day, illustrated in Figure 10, shows the price degrading effect of the subsidy. Moreover, the LSE has succeeded in lowering its overall portfolio cost to procure capacity through the action of subsidizing the higher cost (\$200/MW-day) resource and at the same time has cross-subsidized the rest of the load within the PJM footprint.

Figure 10. Illustrates Suppressed Price From Clearing Sponsored 1,000 MW Asset



Unintended Consequences of Out-of-Market Subsidies

Subsidies to generation – whether designed to suppress overall clearing prices or simply to spur new entry or retain investment in order to advance other “societal benefits” – means an “uneconomic” resource is introduced or retained in the PJM market with an expense that ripples through several areas of the markets.

Comparing Figure 8 and Figure 9 above illustrates how a buyer (an LSE) can be motivated to “overpay” a single generator with the blessing (or at the direction) of the regulator and in so doing (due to operation of the single-clearing-price function of PJM’s capacity market) reduce its total costs incurred in procuring capacity to meet its load and reserve obligations. Revisiting the example above, offering the sponsored resource offered into the market in a manner that ensures it will clear (a \$0/MW-day offer) will shift the supply curve to the right (Figure 10) and lower the LSE’s total outlay from \$900,000 (Figure 8) – the amount it would pay had it not arranged for the preferred asset – to \$800,000 (Figure 9).

Given the relatively steep demand curves employed in capacity markets, even a modest level of subsidized supply can significantly impact clearing prices. The artificial increase in supply resulting from state action to subsidize incumbent generating facilities or to attract new entry (neither of which is supported by organized market prices) also can prevent new, more efficient entry. The simplified example above assumes that, if the state-sponsored resource does not clear (or, if it just does not exist), then 5,000 MW of incumbent resources would clear. However, the example does not consider a new entrant potentially offering into the auction at a price above the sponsored resource (*i.e.*, an offer exceeding \$0/MW-day) and clearing, thus displacing an older, less efficient incumbent resource.

The harm caused by sponsored resource includes:

- artificial suppressing of clearing prices
- starving otherwise competitive incumbents from revenues they need to cover their costs of ongoing operation
- the potential “crowding out” of efficient new entry in favor of retaining less efficient, more costly to operate, and likely less environmentally desirable, older resources.

An economically inefficient resource clearing PJM’s capacity market harms not just the price signal and resource mix of capacity, its participation in energy and ancillary services markets likely degrades those markets as well. Certainly, the participation of a resource that otherwise would not have been built or one that would have retired, necessarily will be at the expense of some other energy or ancillary services supplier. Quantifying the extent and consequence of this harm

depends on a multitude of complex interdependent variables, which this paper does not attempt to simulate or to demonstrate empirically. In the final analysis, the competitiveness of a resource in PJM will be determined by the revenues it earns from all PJM markets – energy, capacity and ancillary services. Thus, it is reasonable to assume that resources that must be propped up by external subsidy to be able to offer capacity into PJM's capacity market also will distort energy and ancillary service price outcomes. An older unit that should have exited, but for a subsidy, likely will displace a lower heat-rate, new unit that would have exerted the proper downward pressure on energy market prices. New entry brought in on the back of a subsidy likely will improperly exert this same pressure depriving incumbent resources of energy market revenues they should have earned.

In ISO/RTO regions with developed capacity markets, including PJM, the FERC has acknowledged the various harms described above and has accepted mitigation rules designed to scrutinize offers associated with state-sponsored resources. The objective of the mitigation rules accepted by the FERC, which in PJM require that an offer reflect the resource's actual costs, is to ensure that the offer is competitive, notwithstanding any out-of-market revenues derived from a contract for differences. This market impact is one reason why federal courts to date have invalidated, under constitutional doctrines of preemption, state subsidies that appear designed to target price outcomes in the capacity markets overseen by the FERC.⁸¹ The U.S. Supreme Court recently affirmed these lower court decisions, albeit in a narrowly drawn opinion that will likely be interpreted as applying only to those subsidies that interfere directly (and probably by design) with a FERC-approved wholesale rate.⁸²

PJM Markets and Interests That Can Be Argued in Terms of Electric Reliability

Some states in the PJM footprint are contemplating or engaging in actions that bear directly on investment in (or retention of) generating facilities, for the purpose of advancing state and local policy interests not recognized by the PJM markets. However, simply put, the purpose of PJM's markets is not to advance environmental interests, protect jobs in local communities, stem declining tax revenues in rural school districts or keep prices low to spur industrial economic activity. Rather, PJM's duty, as shared with its stakeholders and as overseen by the FERC, is to continually assess the performance of PJM's markets in producing accurate prices signals that encourage efficient resource investment and retirement decisions so as to maintain operational integrity and long-term reliability of the electric system.⁸³

While some policy goals may be closely associated with PJM's core mission of providing least-cost reliable electricity, yet they are not reflected in market prices. For example, some commentators may argue that organized electricity markets should account for and accommodate environmental regulations and, in so doing, should provide financial incentives to sustain nuclear resources that could help meet policy objectives regarding carbon emissions.⁸⁴ While undoubtedly linked, environmental policy objectives are distinct from PJM's objectives; ultimately to the extent maximizing one policy objective

⁸¹ These power purchase agreements were struck down on preemption grounds by the federal district and appellate courts. See, *N.J. Board of Public Utilities v. FERC*, 744 F.3d 74 (3d Cir. 2014) and *PPL EnergyPlus, LLC v. Nazarian*, 753 F.3d 467 (4th Cir. 2014),

⁸² *Hughes v. Talen Energy Marketing, LLC.*, United States Supreme Court Docket Nos. 14-614 & 14-623, decided April 16, 2016.

⁸³ Perfection, with the benefit of hindsight, is not the standard. Investment decisions sometimes fail to incorporate relevant factors; and, in hindsight, markets sometimes misallocate capital. However, these "errors" arguably occur to a lesser extent in market environments like PJM's than in non-market environments, where monopolists and regulators handpick investment. Also, as repeatedly noted, in PJM risk is primarily borne by the investor, not by ratepayers.

⁸⁴ At least one commentator has opined that the economic threat to certain nuclear facilities shortsightedly removes from the climate policy equation perhaps the most efficient zero-emitting form of power generation. She blames organized electricity markets for exposing the economic vulnerability of those facilities while not valuing in some manner the public good of zero-emission generation. See Todd-Whitman, *Why Closing Nuclear Power Plants Is Short-Sighted, The Wall Street Journal* (Nov. 16, 2015) ("Making matters worse, poorly structured electricity markets are putting at risk other well-operated, proven nuclear-energy facilities in New York, Ohio, Illinois and other states. Once closed, these plants won't reopen. We must act now before it is too late.").

requires a trade-off with the other, that decision is one for lawmakers and regulators, not market administrators.⁸⁵ Having said that, from a pragmatic and an economic perspective, the more important question is not whether valid environmental interests are justifiably advanced by political entities, but whether the means used to advance these interests (including subsidies) are well designed in light of companion electricity market designs. There are ways to optimize competing interests, and, clearly, certain policy actions taken to promote one interest with consequence to the other can be less desirable and more harmful than alternate options. PJM's role is to inform the debate so that decision-makers can strike an optimal balance between environmental objectives and electric system reliability and the cost to the customer. Like maintaining jobs and the economic vitality of local communities, environmental interests associated with generating electricity, while clearly valid, are not properly advanced (nor countermanded)⁸⁶ by electricity market design. But electricity markets can accommodate transparent and well-designed programs that pursue particular environmental policy objectives.

Resource Diversity

Another interest currently debated in the industry is the public value of having a portfolio of generation resources with a diverse fuel supply. Because resource diversity can factor into system reliability, the question of whether PJM's markets should more explicitly value fuel diversity warrants closer examination. Some commentators have claimed that PJM's markets are flawed because PJM has resisted pursuing what may be described as a "two wrongs make a right" approach to market design, namely, imposing an "adder" to recompense legacy assets for the price-suppressing effects of subsidies given to certain types of politically-favored resources.⁸⁷ The concern over the future viability of legacy generation that is heavily dependent on energy market revenues⁸⁸ and resulting harm to grid reliability over the longer term should these units retire is not unique to PJM.⁸⁹ Still, PJM believes the goals of organized market design do not include counteracting existing subsidies by providing enhanced revenue opportunities to non-subsidized resources. However, the somewhat related question of whether PJM's markets should promote fuel diversity is more complex.

Having a diverse generation portfolio, thus avoiding overreliance on one fuel type, arguably is a system reliability interest. To the extent a resource provides services or attributes that further the reliability mission of the ISO/RTO, the market should compensate for those services and attributes. Today, with new generation dominated by natural gas facilities, two themes emerge. First, delivered natural gas is more of a "just-in-time" fuel compared to fuel for coal and nuclear facilities, which have on-site fuel storage.⁹⁰ This fuel attribute can challenge the availability of a natural gas resource relative to other fuel types, as was highlighted in eastern PJM during the "Polar Vortex" of January and February 2014. Second, fuel diversity can act as a hedge against future shocks. Therefore, an ISO/RTO may be imprudent to "go all in" on natural gas

⁸⁵ Retired Exelon Chief Executive John Rowe, when discussing the challenges facing certain facilities in the Exelon nuclear fleet, acknowledged this point when he opined that the "proper market-driven" answer is to shut down "uneconomic" nuclear facilities, and "if the real reason to keep them running is a public policy reason, then the public has to help bear the cost of doing that." Tomich, *Former Exelon CEO Rowe: Shutting down struggling nukes is 'the proper market-driven answer'*, E&E Publishing, LLC (July 27, 2015) (available at <http://www.eenews.net/stories/1060022403>).

⁸⁶ An illustration of what is meant here by "countermanding" is provided in footnote 87, *infra*, and the accompanying text.

⁸⁷ See e.g. Deposition Testimony of Larry Makovich, PUCO, Case No-14-1297-EL-SSO at 159, line 6 ("My testimony is that renewable mandates have suppressed the cash flows for base load power plants, and both these plants (Sammis and Davis-Besse) are base load power plants").

⁸⁸ Renewable resources typically produce energy at a zero or even, taking into account production tax credits, a negative marginal cost of energy. Their ability to act as price takers in PJM's energy markets, lowers energy clearing prices, and reduces the infra-marginal rents earned by capital intensive fossil and nuclear generation – rents that are necessary to cover on-going costs of operation and that contribute to capital costs.

⁸⁹ See, e.g., ISO-NE Revised Discussion Paper, *The Importance of a Performance-Based Capacity Market to Ensure Reliability as the Grid Adapts to a Renewable Energy Future*, pp. 5-6 (October 2015).

⁹⁰ The "real time" delivery challenge of electricity underscores the concern in relying on a "just-in-time" fuel supply.

because of unforeseen or underappreciated risks, such as a national ban on hydraulic fracturing or an accident that might change the supply and price dynamic for the fuel.

Regarding the first theme, it is true that certain fuel-type generating facilities might naturally provide a particular attribute valued by an ISO/RTO. Other factors being equal, a coal facility with coal in the yard offers greater dependability than a natural gas peaking facility with non-firm fuel supply. Likewise, a coal or nuclear facility will provide greater inertia to the bulk power system than a solar panel,⁹¹ and a battery will provide faster and more controlled frequency response than a natural gas combined-cycle facility. However, from the perspective of the ISO/RTO, it is the attribute (e.g., dependability, inertia or frequency response) that is needed in the correct proportion, not necessarily a certain ratio of fuel type, even if that fuel type may be closely associated with the desired attribute.

PJM's Capacity Performance initiative addressed a shortcoming in PJM's capacity market by recognizing that the market, as designed, was not adequately valuing the reliability of a highly dependable and available fuel supply. The correction came not by directing a premium for a particular fuel type that could be stored on-site but by pricing the dependability attribute and allowing all resources, regardless of fuel type, the flexibility to determine how they may or may not provide the desired attribute. ISO-New England, another U.S. operator of a forward capacity market, voices a similar opinion in commenting on arguments often advanced to justify intervention to support legacy generation:

While policy initiatives like these may be desirable for other reasons, such approaches should not be needed to ensure reliability, or efficient market responses to an increased penetration of renewable resources. The current market design should ensure adequate resources to meet the reliability standards for which the markets are designed, as long as prices in the capacity market are appropriately formed. Appropriate price formation in the capacity market should ensure that the resulting resource mix appropriately complements the capabilities and limitations of the renewable resources entering the market.⁹²

Regarding the second theme, a diverse generation portfolio can provide a hedge against future shocks that could abruptly and dramatically change the relative appeal of one fuel over another. By their nature, large generating facilities cannot be made to appear on the system overnight; and, once shuttered, those resources may be gone for good. Given this reality, ISOs/RTOs may want to maintain a diverse set of resources, including resources that could be "uneconomic" in the short term, to hedge against future shocks.⁹³ While the merits of the fuel hedging argument can be debated, the issue can be fairly characterized as one of system reliability and thus arguably one that PJM should address in market design. However, due to the highly subjective decisions involved in determining the "correct" resource mix and the means and level of

⁹¹ A greater penetration of renewable resources has prompted the question of whether ISOs/RTOs should compensate for inertia. See Alliance for Sustainable Energy, LLC, *Market Evolution: Wholesale Electricity Market Design for 21st Century Power Systems*, p. 23 (October, 2013) (available at <http://www.nrel.gov/docs/fy14osti/57477.pdf>) ("If some resources do provide the service (system inertia), and others do not, however, then some sort of compensation might be required.").

⁹² *Infra*, note 89, *ISO NE Revised Discussion Report*, at p. 7.

⁹³ While this caution against overreliance on a single fuel is advanced today in the face of the prevailing "dash to gas," the most recent actual illustration of the risk can be found in the nuclear industry. The Fukushima Daiichi accident in 2011 resulted in dramatic policy, regulatory and public reaction that has materially increased safety compliance costs facing nuclear generation. These added costs have clearly factored into the closure of several nuclear facilities in the United States. In Japan, the future of dozens of nuclear facilities remains murky, with only one facility (Sendai) presently fully operational. In Germany, the Fukushima Daiichi accident accelerated plans to shutter existing nuclear facilities, advancing to 2022 a date by which the country has pledged to no longer rely on nuclear generation.

compensation to ensure that the desired mix is maintained, the matter lends itself to energy security policy determinations beyond the purview of an ISO/RTO.⁹⁴ Those are issues better addressed by legislators and regulators.

In conclusion, much of the fuel diversity criticism leveled at organized market design can be more appropriately recast as an issue of resource attributes needed to reliably and efficiently operate the system or dismissed as raising policy issues outside the proper scope of the ISO/RTO. What remains, namely the value of a diverse portfolio in hedging against future fuel shocks, (1) raises a “problem” that is speculative and not presently manifest in PJM and (2) would call for a solution that is subjective, complex and dependent on national or at least regional policy choices.

Diverse State Regulatory Environments in PJM: Subsidies Compared to Rate Regulation

The state contracting actions described as subsidies in PJM have been taken by states that legislatively elected to undertake retail competition that, in various forms, separated (or unbundled) retail utility operations (sales and distribution) from generation.⁹⁵ These states decided that incumbent supply and new generation investment would no longer be supported by rate base (retail customers) but would compete as merchant facilities alongside *other resources* in PJM’s markets to serve load. It is important, however, to consider the nature of these *other resources*. PJM’s markets are regional, spanning all or part of 13 states and the District of Columbia. Not all of these jurisdictions have taken steps to unbundle retail load from supply and several continue to regulate traditional vertically integrated electric utilities whose incumbent and new build generation is supported by the utilities’ captive retail customers. Thus, the *other resources* against which a merchant facility competes in PJM’s regional markets include other merchant facilities *and* facilities whose investment is supported by traditional rate base regulation.

Parties on both sides of the subsidy controversies point out that resources receiving out-of-market revenues through a state-mandated contract are placed in no different a position than resources developed and put into retail rate base by a vertically integrated electric utility pursuant to a state’s traditional cost-of-service regulatory regime. The observation is valid up to a point. Whether legally significant distinctions exist to warrant treating each circumstance differently is a question the courts likely will decide. However, important practical differences bear on the competitiveness of organized wholesale electricity markets.

First, states that have elected to unbundle have decided (explicitly or otherwise) to rely on the wholesale markets administered by PJM to meet the resource adequacy needs of that state going forward. As PJM’s markets are regional, this need will be met by procuring the most economically efficient resources, whether those resources are located in that state or outside of (but deliverable to) that state. Actions these states take to subsidize in-state investment ignoring prices in PJM’s markets, which signal either that no new generation is needed or that incumbent resources are no longer needed, will defeat the market’s ability over the longer term to perform the job of assuring resource adequacy by suppressing the market price below its true economic level. In contrast, traditional rate-regulated states continue to assume the responsibility for meeting their state’s resource adequacy objective and are not relying on PJM’s markets to do so. While rate-based resources, depending on the terms of the regulatory arrangement, can be advantaged in comparison to

⁹⁴ Indeed, many would argue that PJM’s fleet today is more diverse than when coal generation exceeded 50% of the resource mix. Freezing coal piles in the yard, barges locked in on a frozen Ohio or Mississippi river, and supply disruption due to a striking workforce are no longer the system operator’s primary concerns to operational security.

⁹⁵ Examples include actions in New Jersey and Maryland to mandate that their retail utilities contract with new combined-cycle facilities. These actions, which were found by lower courts to impermissibly conflict with the federally-established PJM market, are subject to pending determination by the U.S. Supreme Court. Similarly, actions are being considered in Ohio and Illinois to support, for various policy reasons, incumbent generation facing closure due to the inability of these units to earn sufficient revenues from the PJM’s markets.

merchant resources competing in PJM's markets, like many other similarly well established and programmatic subsidies (such as production and investment tax credits for renewable resources), the rate regulatory regime is a risk understood and accepted by the merchant at the time of its investment.⁹⁶ This contrasts distinctly with one-off, unit-specific regulatory intervention. These actions are unpredictable, largely because they cannot be reconciled with the otherwise explicit regulatory policy of that state to rely not on regulated utilities and their captive ratepayers but on markets and investors to assure adequacy.

Second, the history and evolution of cost-based ratemaking in many jurisdictions demonstrates an enlightened awareness of the shortcomings of that model, as described earlier in this paper. Recognizing these concerns, rate regulators in traditional cost-of-service jurisdictions do undertake competitive procurements and evaluations of "build versus buy" alternatives⁹⁷; and there is reason to believe that such comparisons take place with greater rigor when state regulators have readily visible alternatives placed before them, such as provided by PJM's transparent and liquid markets. An asset that comes into the market based on an open, competitive solicitation does not present the same threat as an administratively subsidized resource whose costs are justified for political or social reasons that may not reflect the electricity policy objectives of the state public utility regulator, much less PJM. Indeed, even within the so-called deregulated retail jurisdictions in PJM, generation is contracted under multiyear procurements as an element of such state's competitive retail auctions.⁹⁸

⁹⁶ Merchant investment has continued to add assets in PJM knowing that such investment will have to compete with new entry supported by "non-market" (i.e., rate regulated) constructs. See "New Generation in the PJM Capacity Market" (2016) by Monitoring Analytics, online at http://www.monitoringanalytics.com/reports/Reports/2016/New_Generation_in_the_PJM_Capacity_Market_20160504.pdf. Notwithstanding this competitive challenge to market driven investments, merchant entry in PJM has significantly exceeded investment supported by rate regulation. Moreover, what is particularly noteworthy is that at least an equal weight of this merchant entry has come from private equity and private energy development funds, as opposed to the handful of publicly traded merchant generators or merchant affiliates of utility companies active in PJM. (Id. at p.9). Two conclusions can be reasonably drawn. First, having evaluated the overall, mix of varying state regulatory profiles in PJM, merchant investment is still prepared to enter PJM to compete alongside *some level* of assets supported by regulatory cost recovery. Changes in this mix, however, do appear to upset settled expectations of merchant investors and could become so unbalanced such that PJM in the future might no longer present an attractive opportunity for new merchant investment. Second, private equity theoretically deploys its capital agnostically, which is to say to investments that offer an attractive return regardless of their type. In contrast, publicly traded institutions that have defined themselves as "merchant electricity providers" have strategically committed to a business model where investment is made to develop and operate merchant generation. The robust participation in PJM by completely "voluntary" capital brought by private equity and private funds, suggests that PJM's markets remain competitively attractive relative to other generic investment opportunities.

⁹⁷ An example in PJM can be found in the 2013 amendments to the Virginia Electric Utility Regulation Act requiring an incumbent rate regulated utility to consider and evaluate alternative resource options, including those offered by third-party competitors. See, Title 56, *Public Service Companies*, Chapter 23. Virginia Electric Utility Regulation Act § 56-585.1.

⁹⁸ See, e.g., Citation to Maryland and New Jersey SOS and BGS.GB

Conclusion

Understanding the advantages and disadvantages offered by organized electricity market design to manage the exit and entry of generation needed to maintain a reliable electric system is still evolving. This paper acknowledges that market tools face challenges relative to the traditional regulated model, particularly in accommodating environmental, social and political interests distinct from the singular mission to which markets are charged – delivering the most cost efficient resources needed to serve customers reliably. However, the paper also suggests the following key advantages:

- PJM is handling the exit of obsolete and uncompetitive generation in a comparable manner to regulated regimes.
- PJM is avoiding investment in highly-risky, highly capital-intense experimental utility-scale projects.
- PJM is successfully bringing online, the most cost-effective new generation at prices only somewhat higher than regulated regimes. But in so doing, PJM is placing on investors – and not ratepayers – the risk in these uncertain times that a particular investment made today is unexpectedly rendered uneconomic tomorrow.
- Moreover, once that risk is accounted for and valued in financial markets, it appears consumers are paying overly generous returns to regulated investment, compared to what they are paying merchant investors.

Realizing the “investment efficiency” advantages of PJM’s markets can require policymakers to accept tough choices because efficient market outcomes may inflict harm to other policy objectives. Policymakers must weigh these trade-offs, but understand that pursuing individual actions that “defeat” efficient market outcomes will aggregate to a point they will altogether thwart effective operation of the market to the point it can no longer be relied upon to govern resource exit and entry and attract capital investment when needed.

While not the subject of this paper, once these trade-offs and consequences are appreciated, policies to protect or advance other social, economic or political interests can be implemented in such a way as to minimize or even eliminate the destructive harm to electricity market structures. Informed action of this sort will preserve the ability of PJM’s markets to realize the “investment efficiencies” described in this paper, while also accommodating other social objectives.