UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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Grid Reliability and Resilience Pricing	)	Docket No. RM18-1-000
	)	

COMMENTS OF THE INDEPENDENT MARKET MONITOR FOR PJM

Pursuant to notice issued October 2, 2017, in the above referenced proceeding, Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor ("Market Monitor") for PJM Interconnection L.L.C. ("PJM"), submits these comments. The Commission notice responds to the release by the Secretary of Energy, pursuant to section 403 of the Department of Energy Organization Act, 42 U.S.C. § 7173 (2012), of a proposed rule on September 28, 2017, for final action ("DOE Proposal") by the Commission.[1]

Approving the DOE Proposal would replace regulation through competition with an unworkable hybrid of competitive markets and cost of service regulation. The eventual result would be the demise of competitive markets in the PJM Region. The DOE Proposal does not serve the public interest because the markets can better address all of the concerns that are the basis of the DOE Proposal. If the reliability rules need enhancement, the reliability rules should be enhanced. The DOE Proposal should be rejected. The PJM Region needs more competition, not less.

1 *Grid Resiliency Pricing Rule*, Docket No. RM18-1, 82 Fed. Reg. 46940 (October 10, 2017) ("DOE Proposal").

A. The DOE Proposal Does Not Identify an Emergency or Even an Issue. The Public Can Have Confidence in Markets If They Are Allowed to Operate Without Interference.

The DOE Proposal correctly states the importance of the electric power grid to the U.S. The importance of the grid and the reliability of the grid are part of the core mission of PJM and other RTOs/ISOs. The Commission decided in 1999 to use competitive wholesale power markets to ensure that reliable electric power would be provided to customers at the lowest possible cost. The Commission made a clear and explicit decision to rely on competitive wholesale power markets as a substitute for cost of service regulation.[2] The Commission did so in significant part because markets can improve on cost of service regulation with its known incentive defects by providing a flexible alternative that relies on market price signals to provide incentives to market participants to compete to provide power at the lowest possible cost.

The DOE Proposal fails to identify any market design issue that needs a solution. The DOE Proposal fails to provide any evidence or convincing rationale for reversing the last 17 years of experience with markets in favor of a return to the discredited cost of service paradigm.

B. The DOE Proposal Would Impose Significant Costs on Customers

While the DOE Proposal does not state exactly how it would require RTO/ISOs to define full recovery of the cost of service, it is clear that the Proposal would require a form of cost of service regulation. Cost of service regulation requires the payment of all costs of a

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2 *See*, *e.g.*, *Regional Transmission Organizations*, Order No. 2000, FERC Stats. & Regs.¶ 31,089 *mimeo* at 4 (1999) ("Competition in wholesale electricity markets is the best way to protect the public interest and ensure that electricity consumers pay the lowest price possible for reliable service."), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

generating unit including the return on and of capital and all operating and maintenance expenses.[3]

The Market Monitor has estimated the cost of implementing the DOE Proposal using a range of assumptions so that the cost of each option can be considered by the Commission. It is unlikely that there will be a full rate case for each affected unit, given the large number of units. When public utility commissions did rate cases for large new units, the process frequently took between nine months and a year for each unit because it required detailed review of operating costs, fixed costs, depreciation, capital structure and the cost of capital. Assuming that the DOE Proposal would require use of a more generic approach, the Market Monitor has estimated the additional costs to customers associated with the DOE Proposal.

Consistent with the DOE Proposal's directive that this approach applies only to coal and nuclear units, the units capable of carrying a 90-day on site fuel supply, not currently subject to cost of service regulation, the Market Monitor identified all nuclear and coal plants in the PJM footprint and excluded those subject to cost of service regulation by a state public utility commission or owned by a public power entity (Table 1).[4] [5]

Table 1 Installed capacity of units in the market[6]

	Units in the market (not cost of service)					
	2014		2015		2016	
	No. Units	ICAP (MW)	No. Units	ICAP (MW)	No. Units	ICAP (MW)
Coal	75	24,021	69	23,992	67	24,324
Nuclear	27	28,080	27	28,080	27	28,080
Total ICAP	102	52,101	96	52,072	94	52,404

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3 *See* DOE Proposal at proposed CFR 35.28(10)(iii)(B).

4 The analysis includes external capacity resources that rely on PJM capacity market for capacity revenues and are not under cost of service regulation.

5 Public power entities generally recover costs from customers using the cost of service approach.

6 The units and MW included in this analysis are affected by unit retirements (reduction) and units converting from FRR to market status (increase).

The Market Monitor has calculated the costs of implementing the DOE Proposal under three sets of assumptions about how the cost of service rate would be set for nuclear and coal units: 100 percent of replacement cost; 50 percent of replacement cost and 25 percent of replacement cost. The Market Monitor is not asserting that one of these approaches is what the DOE Proposal intends but is presenting these estimates to provide a range of possible impacts based on the assumptions that the Commission may think relevant. The costs do not vary linearly with replacement costs but the range of costs provides information for the consideration of the Commission and a basis for approximate interpolation. The Market Monitor can provide the costs of the DOE Proposal using different assumptions if that information would be helpful to the Commission.

The estimates of costs use the full replacement cost of nuclear and coal units (Table 2), 50 percent of full replacement cost (Table 3) and 25 percent of full replacement cost (Table 4).

Table 2 Twenty-year levelized total cost of replacement[7]

	20-Year Levelized Total Cost ($/MW-Day)		
	2014	2015	2016
Coal Fired	$1,381	$1,416	$1,434
Nuclear	$2,413	$2,563	$2,639

Table 3 Twenty-year levelized 50 percent of replacement cost

	20-Year Levelized Total Cost at 50% ($/MW-Day)		
	2014	2015	2016
Coal Fired	$690	$708	$717
Nuclear	$1,207	$1,282	$1,319

Table 4 Twenty-year levelized 25 percent of replacement cost

	20-Year Levelized Total Cost at 25% ($/MW-Day)		
	2014	2015	2016
Coal Fired	$345	$354	$359
Nuclear	$603	$641	$660

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7 See the *2016 State of the Market Report for PJM,* Volume 2, Section 7: Net Revenue, Table 7-24 Internal rate of return sensitivity for CT, CC and CP generators.

Table 5 shows the difference between the current level of revenues paid to the nuclear and coal units and the level of revenues that would be required if the units were paid at 100 percent of current replacement costs on a 20-year levelized basis. The current level of revenues includes revenues from the PJM capacity, energy and ancillary services markets. The difference in revenues varies by year because PJM market revenues vary by year. For example, the year 2014 had higher energy market revenues as a result of the polar vortex and therefore a smaller difference between PJM market revenues and the revenues under the DOE Proposal.

The current replacement value of a coal plant is $1,434 per MW-day. The current replacement value of a nuclear plant is $2,639 per MW-day. For comparison, the gross cost of new entry (CONE) for a new combustion turbine is $312 per MW-day and the gross cost of new entry for a new combined cycle is $406 per MW-day.[8]

In 2016, the DOE Proposal would result in an increased cost to customers of about 32 billion dollars, if the nuclear and coal units were all paid the current replacement value (Table 5). That increase equals 384 percent of the total payments for capacity in PJM in 2016, 144 percent of the total payments for energy in PJM in 2016 and 84 percent of the total cost of wholesale energy in PJM in 2016.

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8 *2016 State of the Market Report for PJM,* Volume 2, Section 7: Net Revenue, Table 7-24 Internal rate of return sensitivity for CT, CC and CP generators.

Table 5 Additional cost of DOE Proposal at 100 percent of replacement cost[9]

	Additional Cost of DOE Proposal at 100 Percent of Replacement Cost ($ in millions)		
	2014	2015	2016
Coal	$8,223	$10,550	$11,222
Nuclear	$14,999	$19,995	$21,561
Total ($ in millions)	$23,222	$30,545	$32,782
Total ($/MW-Yr)	$445,715	$586,601	$625,571
Total ($/MW-Day)	$1,221	$1,607	$1,714
Total Cost of Capacity ($ in millions)	$7,029	$8,632	$8,530
Total Cost of Energy ($ in millions)	$41,473	$28,064	$22,746
Total Cost of Wholesale Power ($ in millions)	$55,793	$44,141	$38,887
Total Cost as a Percentage of the Capacity Market	330%	354%	384%
Total Cost as a Percentage of the Energy Market	56%	109%	144%
Total Cost as a Percentage of the Wholesale Power Market	42%	69%	84%

In 2016, the DOE Proposal would result in an increased cost to customers of about 13 billion dollars, if the nuclear and coal units were all paid 50 percent of the current replacement value (Table 6). That increase equals 151 percent of the total payments for capacity in PJM in 2016, 57 percent of the total payments for energy in PJM in 2016 and 33 percent of the total cost of wholesale energy in PJM in 2016.

Table 6 Additional cost of DOE Proposal at 50 percent of levelized cost

	Additional Cost of DOE Proposal at 50 Percent of Replacement Cost ($ in millions)		
	2014	2015	2016
Coal	$2,276	$4,353	$4,855
Nuclear	$2,765	$6,858	$8,039
Total	$5,041	$11,211	$12,893
Total ($/MW-Yr)	$96,765	$215,307	$246,041
Total ($/MW-Day)	$265	$590	$674
Total Cost as a Percentage of the Capacity Market	72%	130%	151%
Total Cost as a Percentage of the Energy Market	12%	40%	57%
Total Cost as a Percentage of the Wholesale Power Market	9%	25%	33%

In 2016, the DOE Proposal would result in an increased cost to customers of about 3 billion dollars, if the nuclear and coal units were all paid 25 percent of the current

9 See the *2016 State of the Market Report for PJM*, Volume 2, Section 1: Introduction, Table 1-1 PJM Market Summary Statistics: 2015 and 2016.

replacement value. (Table 7) That increase equals 36 percent of the total payments for capacity in PJM in 2016, 13 percent of the total payments for energy in PJM in 2016 and 8 percent of the total cost of wholesale energy in PJM in 2016.

Table 7 Additional cost of DOE Proposal at 25 percent levelized cost

	Additional Cost of DOE Proposal at 25 Percent of Replacement Cost ($ in millions)		
	2014	2015	2016
Coal	$404	$1,290	$1,691
Nuclear	$11	$633	$1,360
Total	$415	$1,923	$3,051
Total ($/MW-Yr)	$7,972	$36,925	$58,223
Total ($/MW-Day)	$22	$101	$160
Total Cost as a Percentage of the Capacity Market	6%	22%	36%
Total Cost as a Percentage of the Energy Market	1%	7%	13%
Total Cost as a Percentage of the Wholesale Power Market	1%	4%	8%

Under these three scenarios, implementing the DOE Proposal would result in an increased cost to customers of between $18 billion and $288 billion dollars over ten years.

Table 8 Cost of Implementing Proposal for 10 Years

	Average of 2014-2016 Cost Over Ten Years ($ in millions)
Additional Cost at 100 Percent of Replacement Cost	$288,498
Additional Cost at 50 Percent of Replacement Cost	$97,154
Additional Cost at 25 Percent of Replacement Cost	$17,964

Regardless of the exact definition of the cost of service, the DOE Proposal would impose significant new costs and risks on customers in the PJM footprint. The introduction of market incentives resulted in significant improvements in the operation of nuclear power plants as well as other power plant types. The removal of market incentives will impose the risk of higher costs on customers and will remove the incentive of unit owners to operate more efficiently and at lower cost.[10]

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[10] In addition, to the extent that coal plants increase their inventory to meet the 90 day fuel supply requirement, the DOE Proposal imposes additional costs on the market. The price of coal would likely rise with its increased demand. The marginal cost of power from coal would correspondingly

In addition to these direct, out of pocket costs, and risks of increasing costs, the DOE Proposal would impose significant opportunity costs on customers. The artificial retention of uneconomic resources will crowd out economic resources and weaken or eliminate the incentives for competitive new entry. The introduction of cost of service subsidies would undermine the incentives for independent investors to develop new power plants that are at the heart of existing competitive markets. These incentives have led to improvements in power generation technology and reduced costs for customers. Investors have taken risks and many investors have lost money. That is how markets work. The Public Utilities Regulatory Policy Act (PURPA) was created in response to the high costs of cost of service regulation and the cost overruns at nuclear power plants in particular.[11] While PURPA was far from perfect, its goal was to introduce competition to power generation in order to bring market discipline to costs. The Commission's subsequent introduction of competition was the next logical step. It would be ironic if cost of service regulation were reintroduced in order to preserve nuclear and coal power plants that have been demonstrated by the market to be uneconomic.

C. Subsidies Are Contagious and Undermine the Competitive Market.

The goal of competition in the wholesale power markets is to provide customers wholesale power at the lowest possible price, but no lower. The PJM markets work. The PJM markets bring customers the benefits of competition. The results of the PJM energy market and the results of the PJM capacity market are competitive and reliable. But the PJM markets, and wholesale power markets in the U.S., face new challenges that potentially threaten the viability of competitive markets.

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increase, decreasing its relative competitiveness in the market and increasing the rate required under the DOE Proposal to cover the cost of service.

11 16 U.S.C. § 2601 et seq.

One of the benefits of competitive power markets is that changes in input prices and changes in the balance of supply and demand are reflected immediately in energy prices. The PJM load-weighted, average, real-time locational marginal price (LMP) was 19.2 percent lower in 2016 than in 2015, $29.23 per MWh versus $36.16 per MWh. PJM real-time, load-weighted, energy market prices were lower in 2016 than at any time in PJM history since the beginning of the competitive wholesale market on April 1, 1999. Energy prices were lower as a direct result of lower fuel prices and the resultant increased role of gas as the marginal fuel.

Another benefit of competitive power markets is that they are dynamic, flexible and resilient. The PJM market has resulted in a reliable system despite significant changes in underlying market forces. Technological innovation and significantly lower gas costs have been key market forces. In PJM, there have been substantial unit retirements as a result of market forces and there has been substantial new market entry as a result of market forces. The PJM market design has worked flexibly to address both market exit and entry without preferences for any technologies.

Particularly in times of stress on markets and when some flaws in markets are revealed, nonmarket solutions may appear attractive. Top down, integrated resource planning approaches are tempting because it is easy to think that experts know exactly the right mix and location of generation resources and the appropriate definition of resource diversity and the appropriate definition of reliability and therefore which technologies should be favored through exceptions to market rules. The provision of subsidies to favored technologies, whether solar, wind, coal, batteries, demand side or nuclear, is tempting for those who would benefit, but subsidies are a form of integrated resource planning that is not consistent with markets. Subsidies to existing units are no different in concept than subsidies to planned units and are equally inconsistent with markets. Proposals for fuel diversity are generally proposals to subsidize an existing, uneconomic technology. Subsidies are tempting because they maintain existing resources and provide increased revenues to asset owners in uncertain markets. Cost of service regulation is tempting because cost of service regulation incorporates integrated resource planning and because guaranteed rates of return and fixed prices may look attractive to asset owners in uncertain markets.

It is essential that any approach to the PJM markets incorporate a consistent view of how the preferred market design is expected to work to provide competitive results in a sustainable market design over the long run. A sustainable market design means a market design that results in appropriate incentives to retire units and to invest in new units over time such that reliability is ensured as a result of the functioning of the market. There are at least two broad paradigms that could result in such an outcome. The market paradigm includes a full set of markets, most importantly the energy market and capacity market, which together ensure that there are adequate revenues to incent new generation when it is needed and to incent retirement of units when appropriate. In the market paradigm, investors absorb the risks associated with investment in and ownership of generation assets. In the market paradigm there is a market clearing price to incent investment in existing units or new units. The market paradigm will result in long term reliability at the lowest possible cost.

The quasi-market paradigm includes an energy market based on LMP, but addresses the need for investment incentives via the long term contract model or the cost of service model. In the quasi-market paradigm, competition to build capacity is limited and does not include the entire PJM footprint. In the quasi-market paradigm, customers absorb the risks associated with investment in and ownership of generation assets through guaranteed payments under either guaranteed long term contracts or the cost of service approach. In the quasi-market paradigm, there is no market clearing price to incent investment in existing units or new units. In the quasi-market paradigm, there is no incentive for entities without cost of service treatment to enter and thus competition is effectively eliminated.

The market paradigm and the quasi-market paradigm are mutually exclusive. Once the decision is made that market outcomes must be fundamentally modified, it will be virtually impossible to return to markets. While there are entities in the PJM markets that continue to operate under the quasi-market paradigm, those entities have made a long term decision on a regulatory model and the PJM rules generally limit any associated, potential negative impacts on markets. That consistent approach to the regulatory model is very different from current attempts to subsidize specific uneconomic market assets using various planning concepts as a rationale. The subsidy model is inconsistent with the PJM market design and inconsistent with the market paradigm and constitutes a significant threat to both.

The issue of external subsidies continued to evolve in 2017. These subsidies are not directly part of the PJM market design but nonetheless threaten the foundations of the PJM capacity market and the PJM energy market as well as the competitiveness of PJM markets overall.

The Ohio subsidy proceedings and the Illinois ZEC subsidy proceeding all originated from the fact that competitive markets result in the exit of uneconomic and uncompetitive generating units. Regardless of the specific rationales offered by unit owners, the proposed solution for all such generating units has been to provide out of market subsidies in order to retain such units. These subsidies are not accurately characterized as state subsidies. These subsidies were all requested by the owners of specific uneconomic generating units in order to improve the profitability of those specific units. These subsidies were not requested to accomplish broader social goals. Broader social goals can all be met with market-based mechanisms available to all market participants on a competitive basis and without discrimination.

The DOE Proposal proposes a much broader market intervention through cost of service regulation for selected technologies that would have a correspondingly large and negative impact on PJM's competitive wholesale power markets.

The proponents of subsidies and of the concomitant significant alterations to the PJM capacity market and energy market designs have not demonstrated that there is a systematic problem rather than an uneconomic unit specific problem. Proponents have not demonstrated that the technologies in question are uniformly uneconomic without subsidies. For example, over the 12 months ended in June 2017, fewer than a quarter of nuclear units in PJM did not recover avoidable costs from energy and capacity revenues despite low energy market prices. All PJM nuclear plants recovered more than 90 percent of avoidable costs for the 12 months ended June 30, 2017, despite the fact that some units were on refueling outages. Assertions about the impact of negative prices are also not supported. Negative LMPs reduced nuclear plant net revenues by an average of 0.3 percent and a maximum of 2.6 percent in 2016.

The proposed subsidy solutions in all cases ignore the opportunity cost of subsidizing uneconomic units, which is the displacement of resources and technologies that would otherwise be economic. A decision to subsidize uneconomic units that are a significant source of energy and capacity has direct and significant impacts on other sources of energy; the opportunity costs of subsidies are substantial. Such subsidies suppress energy and capacity market prices and therefore suppress incentives for investments in new, higher efficiency thermal plants but also suppress investment incentives for innovation in the next generation of energy supply technologies and energy efficiency technologies. These impacts are large and long lasting but difficult to quantify precisely.

Subsidies are contagious. Competition in the markets could be replaced by competition to receive subsidies. PJM markets have no protection against this emergent threat. Accurate signals for entry and exit are necessary for well functioning and competitive markets. Competitive investors rely on accurate signals to make decisions.

The PJM wholesale power markets are not perfect. To the extent that market outcomes are subject to legitimate criticism, it is because the markets have, in some cases, not been permitted to reveal the underlying supply and demand fundamentals in prices. Before market outcomes are rejected in favor of nonmarket choices, markets should be permitted to work. It is more critical than ever to get capacity market prices correct and to get energy market prices correct. A number of capacity market design elements resulted in a significant suppression of capacity market prices for multiple years. PJM has addressed the fundamental issues of the capacity market design in its Capacity Performance design, including price formation, product definition and performance incentives.

PJM has also suggested changes to the PJM market design to increase revenues to specific technologies under the rubric of energy market price formation.[12] Within the market paradigm, the temptation to modify other elements of the PJM energy and capacity market design in order to address asserted issues related to the level of prices or the shape of the supply curve should also be resisted. Prices in PJM are not too low. The PJM supply curve is not too flat. One of the lessons of the history of PJM capacity market design is that design changes based on short term, nonmarket considerations can have long term, significant, negative unintended consequences. The basic logic of LMP should not be modified in order to increase prices, or off peak prices or revenues. The shape of the supply curve does not affect the basic logic of LMP and it should not be arbitrarily modified in order to meet a goal not related to the logic of LMP. The energy market design should not be modified in order to introduce elements of integrated resource planning to favor specific technologies. Improvements to the market design should be made when consistent with the basic market design logic, including better pricing when transmission constraints are violated and better and more locational scarcity pricing and improved incentives for flexible units by ending the practice of paying uplift to units based on inflexible operating parameters.

To the extent that there are shared broader goals related to PJM markets, they should also be addressed. If society determines that carbon is a pollutant, a market approach to carbon is preferred to a technology or unit specific subsidy approach. Implementation of a carbon price for the entire market is a market approach which would let market

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12 See PJM "Energy Price Formation and Valuing Flexibility," P 4, (June 15, 2017) <http://www.pjm.com/~/media/library/reports-notices/special-reports/20170615-energy-market-price-formation.ashx>.

participants respond in efficient and innovative ways to the price signal rather than relying on planners to identify specific technologies or resources to be subsidized. If a shared goal is increased renewables in addition to their carbon attributes, a market-based solution to renewable energy credits (RECs) should be implemented.

Fuel diversity has also been mentioned as an issue. Current fuel diversity is higher than ever in PJM. If there is an issue, the real issue is fuel security and not fuel diversity. Before any significant actions are taken to undo markets in the name of security or resilience, careful analysis is required. PJM markets are secure and resilient and would be significantly harmed by interventions to broadly subsidize preferred technologies. If fuel reliability for gas is a concern, a careful evaluation would include the reliability of gas pipelines, the compatibility of the gas pipeline regulated business model with the merchant generator market business model, the degree to which electric generators have truly firm gas service and the need for a gas RTO to help ensure reliability. If the reliability of coal is a concern, a careful evaluation would include the quality and reliability of coal deliveries under a range of circumstances and the reliability of secondary fuel deliveries. If the reliability of nuclear is a concern, a careful evaluation would include the impact of natural disasters and common mode issues. A careful evaluation of overall market reliability would include the transmission system and the interaction among all elements of the markets in contingency analyses.

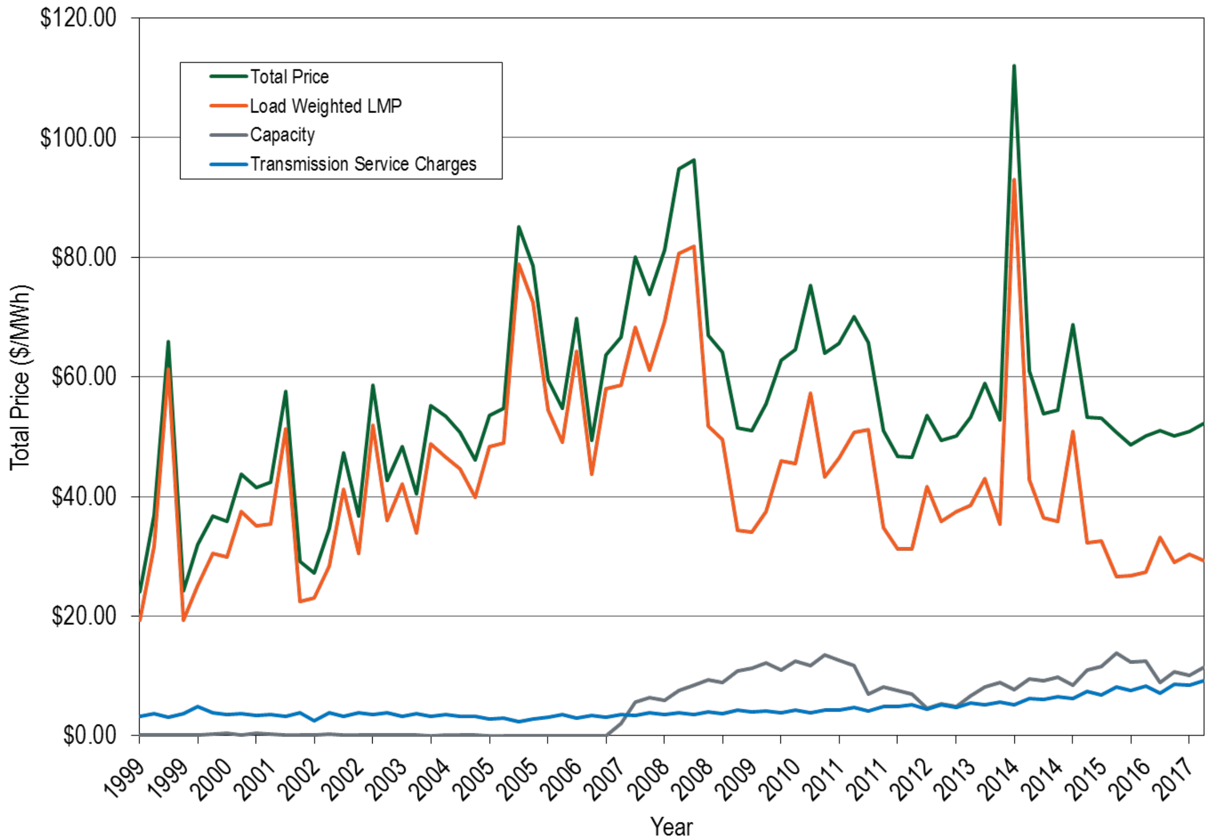
There is no reason to intervene in the markets in order to provide reliability and resilience. The reliability and resilience of PJM markets have continued to evolve through improvements in market design including changes to reserve markets and capacity markets. If PJM or FERC or the DOE identify a need for greater reliability, it can be addressed using market mechanisms.

Competitive markets were introduced as an alternative form of regulation to ensure that wholesale power is provided at the lowest possible price. The PJM markets are working to provide competitive, reliable and resilient outcomes and should be permitted to continue to work.

D. The Evidence from PJM's Markets Shows Efficient, Competitive Provision of Reliable Energy, Including Efficient Signals for Retirement.

In an efficient competitive market, prices equal the short run marginal cost of production. The short run time frame is defined by the time frame in which market participants make decisions and respond to prices. In the case of the energy market, decisions are made daily, hourly, and minute by minute. The majority of short run marginal costs for power production are fuel costs. PJM energy prices track closely with fuel prices. The close relationship between PJM energy prices and the prices of coal and natural gas indicates an efficiently functioning market. Figure 1 shows the historic PJM total price for energy, the energy market Locational Marginal Price ("LMP") component, the capacity market price component, and the transmission cost component. The LMP component is the short run energy price.

Figure 1 PJM all in price of energy 1999 to 2017[13]



Suppliers earn net revenues in the energy market equal to the difference between the LMP at their location on the grid and their short run marginal cost. These net revenues support coverage of avoidable costs of production that are fixed in the short run, such as labor, fuel access, and maintenance costs. Because PJM's reliability needs require it to maintain more available capacity than would exist in the long run equilibrium of a market with entry and exit based purely on energy market profitability, PJM also holds capacity auctions to provide payments sufficient to cover the avoidable costs that are not recovered in the energy market. The capacity market is designed to result in higher auction clearing

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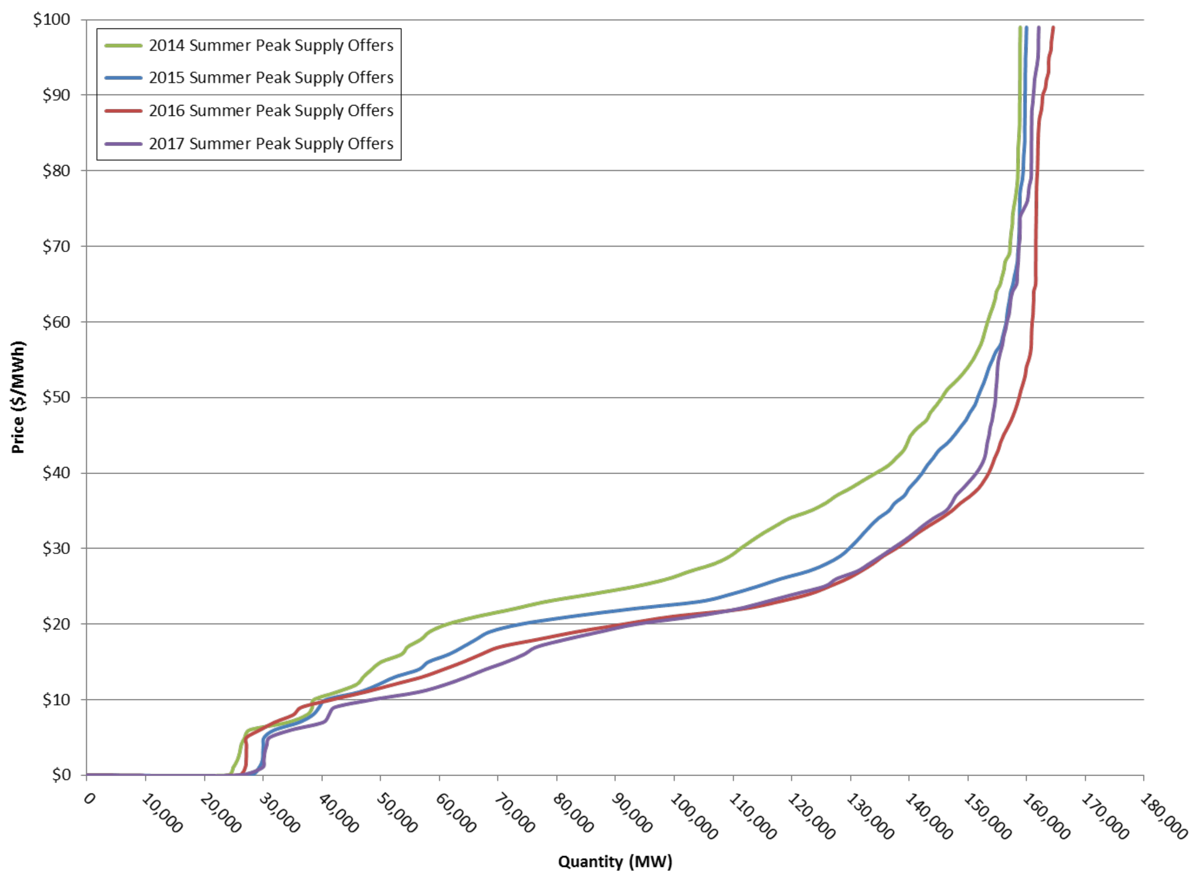
[13] See the *2017 State of the Market Report for PJM: January through June*, Section 1: Introduction, Figure 1-3 PJM all in price of energy 1999 to 2017

prices when energy market net revenues are low and lower auction clearing prices when energy market net revenues are high. The negative correlation of capacity prices with LMP in Figure 1 during the last five years demonstrates the effectiveness of the markets in making the appropriate price adjustments.

The slope of the energy market supply curve impacts the magnitude of energy market net revenues. When the supply curve is flatter, the area below the LMP and above the supply curve, which is net revenue, is smaller. Figure 2 shows the fluctuations in the PJM aggregate average supply curve, which was at its lowest recent levels in 2016.

Figure 2 PJM average supply curve for energy summer 2014 through 2017



The lower levels of short run marginal costs reflected in the supply curve result in lower energy market net revenues and higher capacity market prices. This demonstrates the efficient functioning of the PJM markets. Table 9 shows the historical trend of the percent of units of varying technologies recovering all costs from the PJM markets. Results show that many coal plants do not receive sufficient energy and capacity market revenues to cover their avoidable costs. Two changes affecting coal plant cost recovery are energy market competition from natural gas units, many of which now have lower marginal costs than coal-fired units, and increased avoidable costs related to the mitigation of pollution. The percent of coal units recovering all costs has varied greatly.

Table 9 Proportion of units recovering avoidable costs: 2011 through 2016

	Percent of Units with Full ACR Recovery from Energy and Ancillary Net Revenue						Percent of Units with Full ACR Recovery from All Markets					
Technology	2011	2012	2013	2014	2015	2016	2011	2012	2013	2014	2015	2016
CC - Combined Cycle	55%	46%	50%	72%	59%	63%	85%	79%	79%	95%	88%	93%
CT - Aero Derivative	15%	6%	6%	53%	15%	8%	100%	96%	76%	98%	100%	99%
CT - Industrial Frame	26%	23%	17%	38%	13%	8%	99%	98%	83%	100%	100%	100%
Coal Fired	31%	17%	27%	80%	16%	15%	82%	36%	54%	85%	64%	41%
Diesel	48%	42%	37%	69%	56%	33%	100%	100%	77%	100%	100%	100%
Hydro	74%	61%	95%	97%	81%	79%	81%	77%	97%	98%	100%	100%
Nuclear	87%	65%	94%	100%	61%	32%	94%	84%	94%	100%	90%	74%
Oil or Gas Steam	8%	6%	11%	15%	3%	0%	92%	78%	86%	85%	91%	91%
Pumped Storage	NA	100%	95%	100%	100%	100%	NA	100%	100%	100%	100%	100%

The Market Monitor evaluated the avoidable cost recovery of nuclear units for 2016 and for the 12 months ending with the second quarter of 2017. The results in Table 10 show that at least 25 percent of all nuclear units recovered avoidable costs from the energy and ancillary service markets alone. At least 50 percent of all nuclear units recovered avoidable costs from all markets, including the capacity market. In the year ending June 30, 2017, at least 75 percent of all nuclear units recovered avoidable costs from all markets.

Table 10 Nuclear unit avoidable cost recovery by quartile[14]

		Recovery of Avoidable Costs from Energy and Ancillary Net Revenue			Recovery of Avoidable Costs from All Markets		
Technology	Total Installed Capacity (ICAP)	First Quartile	Median	Third Quartile	First Quartile	Median	Third Quartile
Nuclear (2016)	31,661	61%	88%	105%	91%	119%	135%
Nuclear (July 2016 through June 2017)	31,661	81%	95%	113%	104%	126%	143%

The results use published nuclear plant operating costs of $25.83 per MWh for single unit sites and $18.73 per MWh for multiunit sites as avoidable costs.[15] [16] Over the last 12

14 See the *2017 State of the Market Report for PJM: January through June*, Section 7: Net Revenues, Table 7-13 Avoidable cost recovery by quartile

months, fewer than a quarter of nuclear units did not recover avoidable costs from energy and capacity revenues as a result of higher energy prices, which in most cases more than offsets lower capacity prices. The average LMP increase of 6.0 percent between the 12 months ended June 30, 2017, and 2016 resulted in all nuclear plants in PJM recovering more than 90 percent of avoidable costs for the 12 months ended June 30, 2017.[17]

Persistent failure to recover a unit's costs after several years is a market signal that the unit is uneconomic and at risk of retirement for economic reasons. The Market Monitor identifies units at risk of retirement annually. Units that have either already started the deactivation process or requested deactivation review are excluded from the at risk analysis. Unit revenues are a combination of energy and ancillary service revenues and capacity market revenues. Units that fail to recover avoidable costs from total market revenues, including capacity market revenues, are at risk of retirement particularly if the results are expected to continue. In addition, units that failed to clear the most recent capacity auction(s) are at increased risk of retirement particularly if this result is expected to continue. The profile of units that have not recovered avoidable costs from total market revenues in two of the last three years or have not cleared either the 2018/2019 or the 2019/2020 capacity auctions is shown in Table 11.[18] These units are considered at risk of retirement. These results mean that 14,500 MW of capacity in PJM are at risk of retirement in addition to the units that are currently planning to retire. Coal fired units with an

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15 Operating costs from: Nuclear Energy Institute (August, 2017) "Nuclear Costs in Context," <https://www.nei.org/CorporateSite/media/filefolder/Policy/Papers/Nuclear-Costs-in-Context.pdf?ext=.pdf>.

16 The analysis of nuclear plants uses uniform fuel costs for all units. Net revenue is net of fuel costs.

17 Capital expenditures are generally sunk costs and appropriately excluded from this analysis. To the extent that there are additional annual avoidable costs, the results could differ.

18 Avoidable costs are ACR values and exclude APIR.

average age of 49 years old comprise the majority of this capacity. There are very few nuclear units in PJM that are at risk, based on publicly available data.

Table 11 Profile of units at risk of retirement, 2016

Technology	No. Units	ICAP (MW)	Avg. 2016 Run Hrs	Avg. Unit Age (Yrs)	Avg. Heat Rate
CC - Combined Cycle	4	915	1,002	28	9,523
CT - Aero Derivative	11	192	26	43	15,076
CT - Industrial Frame	44	1,217	123	39	14,542
Coal Fired	25	11,282	4,179	49	10,363
Diesel	4	30	330	25	10,999
Oil or Gas Steam	8	864	2,918	44	11,778
Total	96	14,500	3,197	34	11,391

Retirement of units is not a reliability risk. PJM assesses the reliability impacts of unit retirements and maintains a Reliability Must Run process to provide cost compensation for units that it requires remain in service for short periods for reliability reasons.[19] This process is sufficient to accommodate cost of service support for any units that PJM deems necessary for reliability or resilience that would otherwise retire. There is no need to add an additional process that would distort the market to provide cost of service support to units of a particular fuel class in the name of reliability or resilience.

E. Subsidies to Coal and Nuclear Resources Should Not Distort Prices in the Energy and Capacity Markets.

The DOE Proposal calls for modifications to day-ahead and real-time energy market rates "for the purchase of electric energy…for such resource dispatched during grid operations."[20] It calls for such rates to cover "reliability, resiliency, and on-site fuel assurance, and that each eligible resource recovers its fully allocated costs and a fair return on equity."[21] The proposed rule further states that "compensable costs shall include, but not

[19] PJM OATT § V. Generator Deactivation.

[20] DOE Proposal at proposed CFR 35.28(10)(iii)(A)(1-2).

[21] DOE Proposal at proposed CFR 35.28(10)(iii)(B).

be limited to operating and fuel expenses, costs of capital and debt, and a fair return on equity and investment."[22] A guarantee of full cost of service recovery for dispatch in the energy market is not consistent with the PJM market design. A guarantee of recovery of capital and return on equity is not consistent with the PJM capacity market design.

There are three types of costs that need to be addressed in any market design: short run marginal costs (or incremental costs), costs incurred directly as a result of producing energy for an hour; avoidable costs, annual costs that would be avoided if energy were not produced over an annual period; long term fixed costs, costs associated with an investment in a facility including the return on and of capital.

Short run marginal costs are the only costs relevant to the energy market. Specifically, the competitive energy offer level is the short run marginal cost of production. For the ancillary service markets, it is the short run marginal cost of providing the relevant service, which primarily consists of opportunity costs in the energy market. Avoidable costs and non-sunk fixed costs, net of benefits from participating in the energy market, comprise the competitive offer level for the capacity market. The combined price is the efficient long run price. The efficient energy market, as designed in PJM, is not meant to provide the full long run investment signal for all resources. The efficient alternative to the capacity market for providing the efficient long run price signal is scarcity pricing. Distortions to the short run energy price to artificially favor certain technologies would undermine the competitive functioning of the energy and capacity markets. There are a number of efficient changes to the PJM energy market design that would improve price formation and that should be pursued rather than PJM's approach which would distort energy prices and result in a mismatch between energy market prices and the dispatch signal.

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22 DOE Proposal at proposed CFR 35.28(10)(iv).

F. Generator Performance Evidence Does Not Support Subsidizing Nuclear and Coal Plants.

Commission staff asks whether the DOE correctly characterized the events due to severe weather, such as 2012 Hurricane Sandy and the 2014 Polar Vortex.[23] Historic data from PJM indicates that Hurricane Sandy did not reveal vulnerabilities in the performance of the PJM generation fleet and that the lack of performance during the 2014 Polar Vortex was not limited to natural gas fired generation. Neither the Hurricane Sandy nor the Polar Vortex events support the resilience argument in the DOE Proposal.

The Market Monitor tracks historic performance of PJM generators (Table 12). Each generation technology has a different performance profile. Steam units, a category primarily comprised of coal-fired generation, have the lowest availability rates, 76.3 percent in 2016. Nuclear units have the highest availability rates, 91.7 percent in 2016.

Performance factors include the equivalent availability factor (EAF), the equivalent maintenance outage factor (EMOF), the equivalent planned outage factor (EPOF) and the equivalent forced outage factor (EFOF). These four factors add to 100 percent for any generating unit. The EAF is the proportion of hours in a year when a unit is available to generate at full capacity while the three outage factors include all the hours when a unit is unavailable. The EMOF is the proportion of hours in a year when a unit is unavailable because of maintenance outages and maintenance deratings. The EPOF is the proportion of hours in a year when a unit is unavailable because of planned outages and planned deratings. The EFOF is the proportion of hours in a year when a unit is unavailable because of forced outages and forced deratings.

[23] Commission Staff Questions at 2.

Table 12 Generator performance factors by unit type: 2007 through 2016[24]

	Combined Cycle				Combustion Turbine				Diesel				Hydroelectric				Nuclear				Steam			
	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF
2007	2.3%	6.1%	1.8%	89.8%	4.4%	2.4%	2.5%	90.6%	10.2%	0.6%	1.6%	87.6%	1.3%	7.2%	1.4%	90.1%	1.3%	5.3%	0.3%	93.1%	7.3%	8.6%	2.7%	81.4%
2008	2.1%	5.9%	1.7%	90.4%	2.7%	4.0%	2.2%	91.1%	9.1%	1.0%	1.2%	88.7%	1.3%	7.8%	2.1%	88.8%	1.8%	5.1%	0.8%	92.3%	7.9%	8.0%	2.6%	81.6%
2009	2.7%	6.3%	3.1%	87.9%	1.5%	2.8%	2.3%	93.4%	6.6%	0.6%	1.1%	91.7%	2.3%	8.7%	2.3%	86.8%	4.1%	5.2%	0.6%	90.1%	6.8%	8.5%	3.7%	81.0%
2010	2.6%	8.5%	3.0%	86.0%	1.9%	3.0%	2.0%	93.1%	4.4%	0.4%	1.5%	93.6%	0.7%	8.6%	1.9%	88.8%	2.3%	5.4%	0.5%	91.8%	7.7%	9.3%	3.9%	79.0%
2011	2.4%	9.6%	2.4%	85.5%	2.0%	3.8%	2.4%	91.8%	3.3%	0.1%	1.8%	94.8%	1.7%	11.7%	1.9%	84.7%	2.6%	6.1%	1.2%	90.1%	8.3%	9.2%	4.2%	78.3%
2012	3.6%	8.1%	2.6%	85.7%	2.8%	3.2%	1.7%	92.4%	3.9%	0.7%	2.4%	93.1%	2.8%	6.3%	2.1%	88.8%	1.5%	6.4%	1.1%	91.1%	7.8%	8.7%	5.6%	77.9%
2013	2.4%	8.6%	2.4%	86.5%	5.0%	4.0%	1.9%	89.1%	6.0%	0.3%	1.4%	92.4%	2.3%	7.8%	1.9%	87.9%	1.1%	5.9%	0.7%	92.2%	8.3%	10.2%	4.3%	77.2%
2014	2.6%	10.6%	2.5%	84.4%	6.0%	3.8%	1.9%	88.3%	13.8%	0.4%	2.2%	83.5%	2.5%	9.3%	3.0%	85.2%	1.8%	5.8%	0.9%	91.5%	8.8%	10.3%	5.5%	75.4%
2015	2.1%	10.6%	2.1%	85.2%	2.8%	4.5%	2.5%	90.2%	7.6%	0.3%	2.7%	89.4%	3.7%	9.6%	1.5%	85.2%	1.3%	5.5%	1.2%	91.9%	7.4%	11.3%	4.4%	77.0%
2016	2.6%	10.5%	1.7%	85.1%	2.1%	5.7%	2.7%	89.6%	5.4%	0.2%	2.6%	91.8%	2.4%	7.7%	3.3%	86.6%	1.7%	5.5%	1.2%	91.7%	7.4%	10.4%	5.8%	76.3%

The performance factors in Table 12 reflect events in the past decade that affected unit performance. Most recently, the 2014 Polar Vortex year saw lower availability factors for all unit types except hydroelectric and nuclear. The data show no impact for 2012, the year of Hurricane Sandy.

The most fundamental forced outage rate metric is the equivalent demand forced outage rate (EFORd). EFORd is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate. EFORd measures the forced outage rate during periods of demand, and does not include planned or maintenance outages. A period of demand is a period during which a generator is running or needed to run. EFORd calculations use historical performance data, including equivalent forced outage hours, service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours. The EFORd metric includes all forced outages, regardless of the reason for those outages. Table 13 shows the class average EFORd by unit type.

[24] See the *2016 State of the Market Report for PJM*, Section 5: Capacity, Table 5-27 EFOF, EPOF, EMOF and EAF by unit type: 2007 through 2016.

Table 13 PJM effective forced outage rate (EFORd) by unit types: 2007 through 2016[25]

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Combined Cycle	3.7%	3.7%	4.1%	3.8%	3.4%	4.3%	3.1%	4.3%	2.8%	3.3%
Combustion Turbine	11.0%	11.1%	9.7%	9.0%	8.0%	8.2%	10.7%	15.8%	8.8%	5.8%
Diesel	11.7%	10.3%	9.3%	6.4%	9.3%	5.1%	6.6%	14.8%	9.1%	7.1%
Hydroelectric	2.0%	2.0%	3.2%	1.2%	2.9%	4.4%	3.7%	3.8%	5.2%	3.5%
Nuclear	1.4%	1.9%	4.1%	2.5%	2.8%	1.6%	1.2%	1.9%	1.4%	1.9%
Steam	9.1%	10.1%	9.3%	9.8%	11.2%	10.6%	11.6%	12.1%	10.2%	10.0%
Total	7.0%	7.7%	7.6%	7.3%	7.9%	7.5%	8.1%	9.4%	7.0%	6.3%

EFORd rates follow a consistent historic pattern with the higher than average rates for steam, diesel, and combustion turbine units. Combined cycle, hydroelectric, and nuclear units have lower than average rates. The highest annual EFORd for nuclear units occurs in 2009 when AEP's Cook Unit 1 experienced a forced outage for more than a year after a turbine failure.[26] Only hydroelectric generation shows a higher than usual EFORd in the Hurricane Sandy year, 2012. Combined cycle, combustion turbine, diesel, and steam EFORd peak in 2014.

The largest Polar Vortex EFORd impact was to combustion turbines, reaching 15.8 percent for the year. The Polar Vortex impacts were not limited to gas-fired generation. The diesel EFORd for 2014 is nearly as high as that of combustion turbines, at 14.8 percent. The steam EFORd also peaks, at 12.1 percent, in 2014.

Figure 3 shows the daily outage MW by fuel source during January 2014, the month of the Polar Vortex. The gas outage MW are the most volatile, ranging from 1,650 to 19,000 MW. The coal outage MW are also substantial, ranging from 3,800 to 12,800 MW. The coal outage MW rise with the gas outage MW, especially on January 6 through 10. Oil outage

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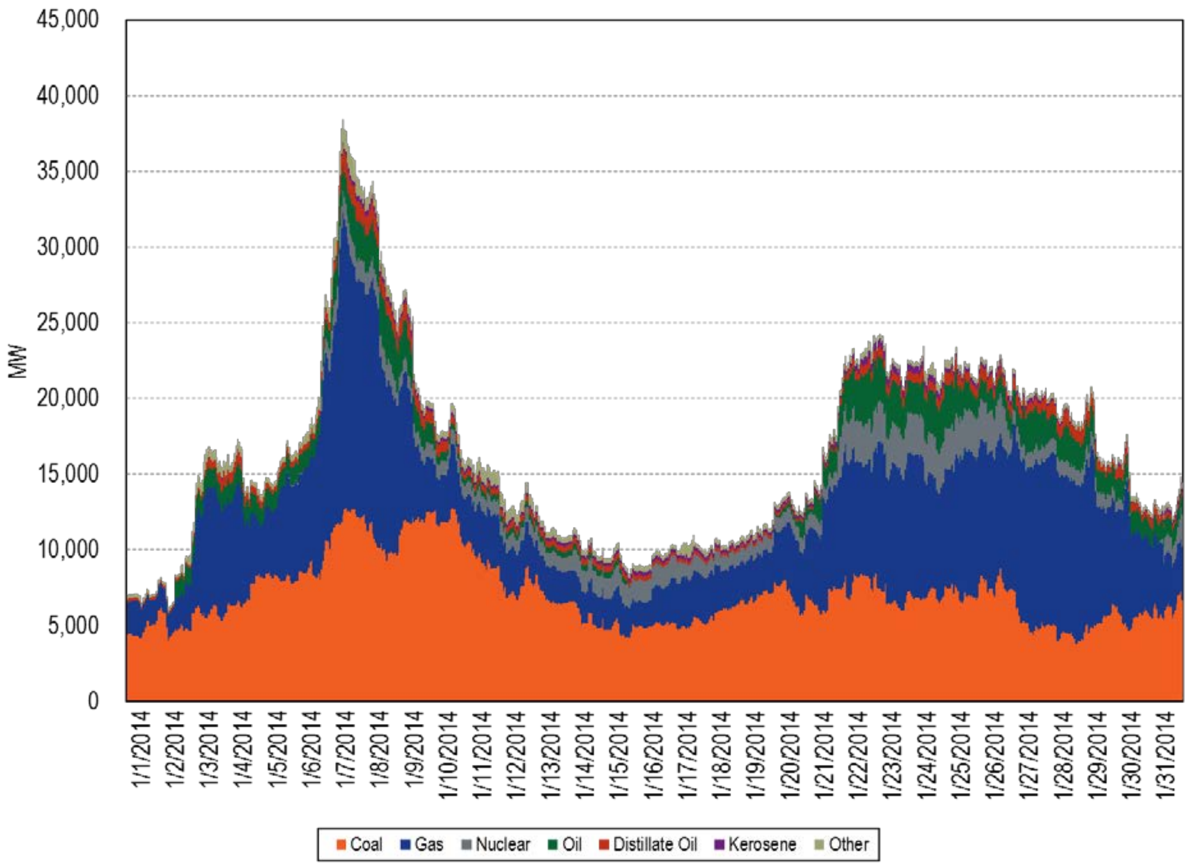
25 See the *2016 State of the Market Report for PJM*, Section 5: Capacity, Table 5-28 PJM EFORd data for different unit types: 2007 through 2016.

26 Reuters, "Update 1 – AEP sees Mich. Cook 1 reactor back in 2009, not Oct.," (October 21, 2009), <https://www.reuters.com/article/utilities-operations-aep-cook/update-1-aep-sees-mich-cook-1-reactor-back-in-2009-not-oct-idUSN2149149520091021>.

MW rise on the same days. During the cold weather week of January 21 through 27, the nuclear outage MW also increase, reaching 2,700 MW.

Figure 3 Generator outages in January 2014 by unit fuel source[27]



All unit types are affected by extreme weather to varying extents. Cold weather means higher demand for gas and higher prices that affect gas-fired generation and coal generators that require gas to start or to stabilize operations. Cold weather also affects fuel stored and transported above ground, coal and oil. Floods affect coal and nuclear units, which are generally located near a water source. Wind turbines are vulnerable to extreme winds and ice. Solar generation is subject to cloud cover variability. All generators are connected to electrical equipment that may be affected by extreme weather. No fuel type

27 See the 2014 State of the Market Report for PJM: January through March, Section 3: Energy Market, Figure 3-38 Conservative operations generation and energy uplift costs: January 2014.

provides a guarantee of reliable operation under all circumstances. No fuel type should receive subsidies on the basis of its asserted reliability under all conditions.

G. Capacity Performance Market Reforms Address the Need for Greater Fuel Security and Incentives for Generator Performance in PJM.

The Capacity Performance market reforms, implemented on June 1, 2016, constituted a significant, constructive effort by PJM to redesign the Reliability Pricing Model ("RPM") capacity market (and the Fixed Resource Requirement ("FRR") Alternative component of RPM) to more closely match payments for capacity with required performance. The market redesign addressed many significant issues with PJM's capacity market design that had been previously identified and that were highlighted based on the performance of the RPM design during the 2014 Polar Vortex.

Although the previous capacity market design implied that capacity resources must perform, the critical incentives and verification measures needed to ensure performance were not in place. The previous rules allowed resources to be paid for capacity even when such resources did not provide energy when it was most needed. Events in January and February, 2014, revealed that capacity market design flaws put reliability at risk by failing to adequately link payments for capacity and incentives to perform when energy is needed.

The previous design assumed physical offers of unit and resource specific capacity, but the rules did not adequately define the physical requirements and the procedures to verify physical offers, and the rules that were in place were not effectively administered. There was uncertainty about whether and how the rules would be enforced.

The previous design paid capacity resources the market clearing price, but failed to impose comparable requirements for the capacity delivered. The previous design allowed inferior capacity product types to suppress prices and drive out competing product types. The previous design failed to deter resource owners from making decisions about resource availability based on economic decisions about whether to procure fuel.

The Capacity Performance design ties performance to payment for capacity and corrects or takes significant steps towards correcting the problems with the previous capacity market design. The guiding principle is that resources that do not perform do not get paid regardless of the reason for nonperformance. The guiding principle is that there are no excuses for nonperformance. If a resource does not perform, it pays back the value of what it sold but did not deliver. In an energy only market, resources do not get paid on days with very high prices unless they provide energy. The capacity market exists only because scarcity pricing, as implemented in the energy market, does not provide adequate revenue to provide incentives to entry and retention.

In October 2016, PJM issued a report describing investment responses to Capacity Performance.[28] PJM states that "generation companies are making generator-specific investments in staffing, infrastructure, and fuel supply." The investments include increased staffing, generator infrastructure, and firm fuel supply. Regarding fuel security, gas generators began procuring firm fuel service and converting gas generators to dual gas and oil generators. Commission staff asks "were the changes both operationally and to the RTO/ISO markets in response to these events effective in addressing issues identified during the 2014 Polar Vortex?" PJM's reported survey results indicate that Capacity Performance produced market responses to increase reliability, directly addressing the vulnerabilities revealed by the Polar Vortex, as intended.

H. Generation Retirements Have Had a Minimal Impact on Fuel Diversity.

Commission staff asks whether "the changing resource mix had a measureable impact on fuel diversity."[29] At the beginning of the new capacity market delivery year on June 1, 2017, PJM installed capacity was 183,099.2 MW. Figure 4 shows the share of installed

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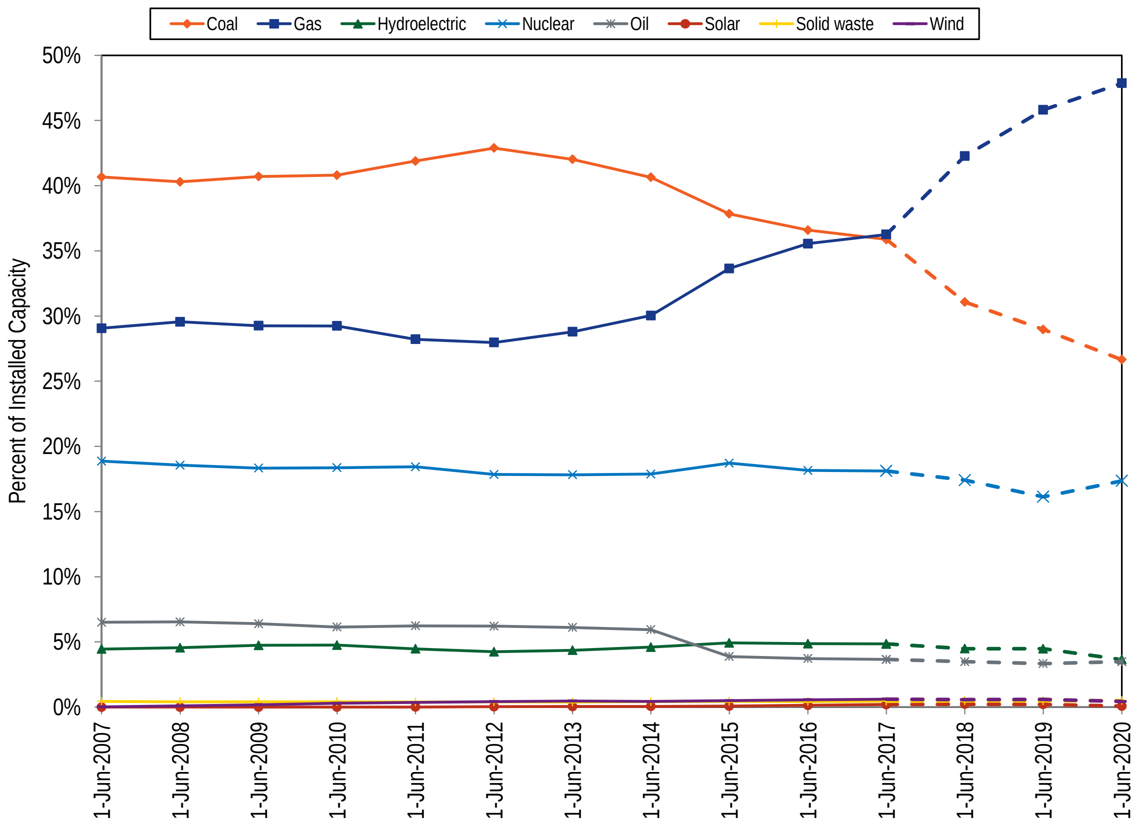
28 "Capacity Performance Driven Investments," PJM report presented to the MC Webinar, October 24, 2016, <http://www.pjm.com/-/media/committees-groups/committees/mc/20161024-webinar/20161024-item-03-resource-investments-in-response-to-capacity-performance-requirements.ashx>.

29 Commission Staff Questions at 2.

capacity by fuel source for the first day of each delivery year, from June 1, 2007, to June 1, 2017, as well as the expected installed capacity for the next three delivery years, based on the results of all auctions held through June 30, 2017.[30] On June 1, 2007, coal comprised 40.7 percent of the installed capacity, reached a maximum of 42.9 percent in 2012, decreased to 35.9 percent on June 1, 2017 and is projected to decrease to 26.7 percent by June 1, 2020. The share of gas increased from 29.1 percent in 2007 to 36.3 percent in 2017 and is projected to increase to 47.9 percent in 2020.

Figure 4 Percent of PJM installed capacity (By fuel source): June 1, 2007 through June 1, 2020



30 Due to EFORd values not being finalized for future delivery years, the projected installed capacity is based on cleared unforced capacity (UCAP) MW using the EFORd submitted with the offer.

Figure 5 shows the fuel diversity index (FDI_c) for PJM installed capacity.[31] The FDI_c is defined as $1-\sum_{i=1}^{N} s_i^2$, where s_i is the percent share of fuel type i. The minimum possible value for the FDI_c is zero, corresponding to all capacity from a single fuel type. The maximum possible value for the FDI_c is achieved when each fuel type has an equal share of capacity. For a capacity mix of eight fuel types, the maximum achievable index is 0.875. The fuel type categories used in the calculation of the FDI_c are coal, gas, hydroelectric, nuclear, oil, solar, solid waste, and wind. The FDI_c is stable and does not exhibit any long-term trends. The only significant deviation occurred with the expansion of the PJM footprint. On April 1, 2002, PJM expanded with the addition of Allegheny Power System, which added about 12,000 MW of generation.[32] The reduction in the FDI_c resulted from an increase in coal capacity resources. A similar, but more significant reduction occurred in 2004 with the expansion into the ComEd, AEP, and Dayton Power & Light control zones.[33] The FDI_c decreased on average 0.3 percent from the first six months of 2016 to the first six months of 2017. The decrease in FDI_c was a result of an increase in the capacity share of gas generators and corresponding small reductions in the share of nuclear, hydro, and coal. Figure 5 also includes the expected FDI_c through June 2020 based on the clearing of RPM auctions. The expected FDI_c is indicated in Figure 5 by the dashed orange line.

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31 Monitoring Analytics developed the FDI to provide an objective metric of fuel diversity. The FDI metric is similar to the HHI used to measure market concentration. The FDI is calculated separately for energy output and for installed capacity.

32 On April 1, 2002, the PJM Region expanded with the addition of Allegheny Power System under a set of agreements known as "PJM-West." See page 4 in the 2002 *State of the Market Report for PJM* for additional details.

33 See the *2016 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for an explanation of the expansion of the PJM footprint. The integration of the ComEd Control Area occurred in May 2004 and the integration of the AEP and Dayton control zones occurred in October 2004.

The FDI_c was used to measure the impact of potential retirements of resources that the Market Monitor has identified as being at risk of retirement.[34] There were 96 resources with installed capacity totaling 14,500 MW identified as being at risk. The dashed green line in Figure 5 shows the FDI_c calculated assuming that the capacity from these 96 resources is replaced by gas generation. The FDI_c under these assumptions would decrease by 0.017 (2.4 percent) from the expected FDI_c for the period June 1, 2017, through June 1, 2020.

Figure 5 Fuel diversity index for PJM installed capacity (January 1, 2002 through June 1, 2020)

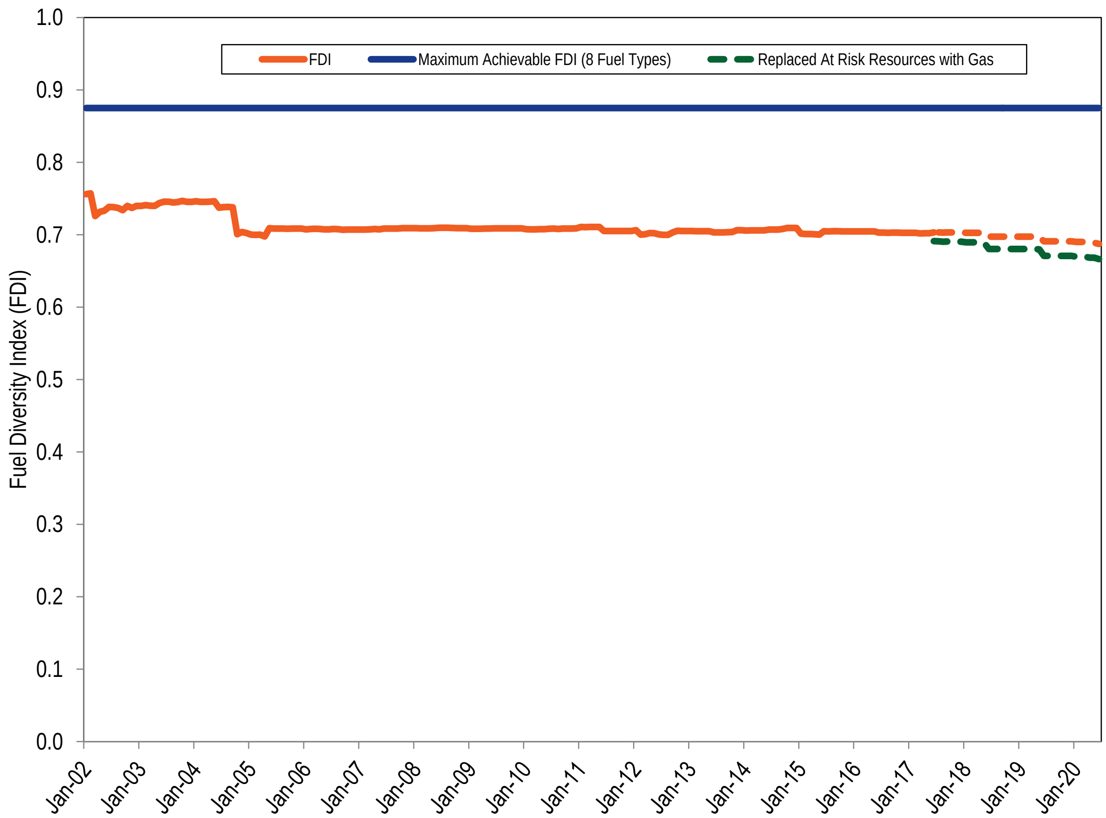

Figure 6 shows the fuel diversity index (FDI_e) for PJM energy generation.[35] The FDI_e is defined as $1 - \sum_{i=1}^{N} s_i^2$, where s_i is the share of fuel type i. The minimum possible value for

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[34] See the *2016 State of the Market Report for PJM, Volume 2*, Section 7: Net Revenue, Units at Risk.

[35] Monitoring Analytics developed the FDI to provide an objective metric of fuel diversity. The FDI metric is similar to the HHI used to measure market concentration. The FDI is calculated separately for energy output and for installed capacity.

the FDI$_e$ is zero, corresponding to all generation from a single fuel type. The maximum possible value for the FDI$_e$ is achieved when each fuel type has an equal share of total generation. For a generation fleet composed of 10 fuel types, the maximum achievable index is 0.9. The fuel type categories used in the calculation of the FDI$_e$ are the 10 primary fuel sources in Table 14 with nonzero generation values. The FDI$_e$ exhibited seasonality in prior years with most of the peaks occurring in the spring and summer months, and the valleys occurring in the fall and winter months. As fuel diversity has increased, the seasonality in the FDI$_e$ has decreased and the FDI$_e$ has exhibited less volatility. A significant drop in the FDI$_e$ occurred in the fall of 2004 as a result of the expansion of the PJM market footprint into ComEd, AEP, and Dayton Power & Light control zones and the increased shares of coal and nuclear that resulted.[36] The increasing trend that began in 2008 corresponds to a period of decreasing coal generation, increasing gas generation and increasing wind generation. Coal generation as a share of total generation dropped 20.5 percentage points from 2008 to 2016 and gas generation increased 19.3 percentage points. Wind generation was 2.2 percent of total generation in 2016. The average FDI$_e$ increased 0.6 percent from the first six months of 2016 to the first six months of 2017.

The FDI$_e$ was used to measure the impact of potential retirements by resources that have been identified as being at risk of retirement by the Market Monitor's net revenue adequacy analysis.[37] There were 96 resources with installed capacity totaling 14,500 MW identified as at risk. The 96 at risk resources generated 43.6 GWH in the twelve month period ending June 30, 2017. The dashed line in Figure 6 shows the FDI$_e$ calculated assuming that the 43.6 GWH of generation from the 96 at risk resources were replaced by

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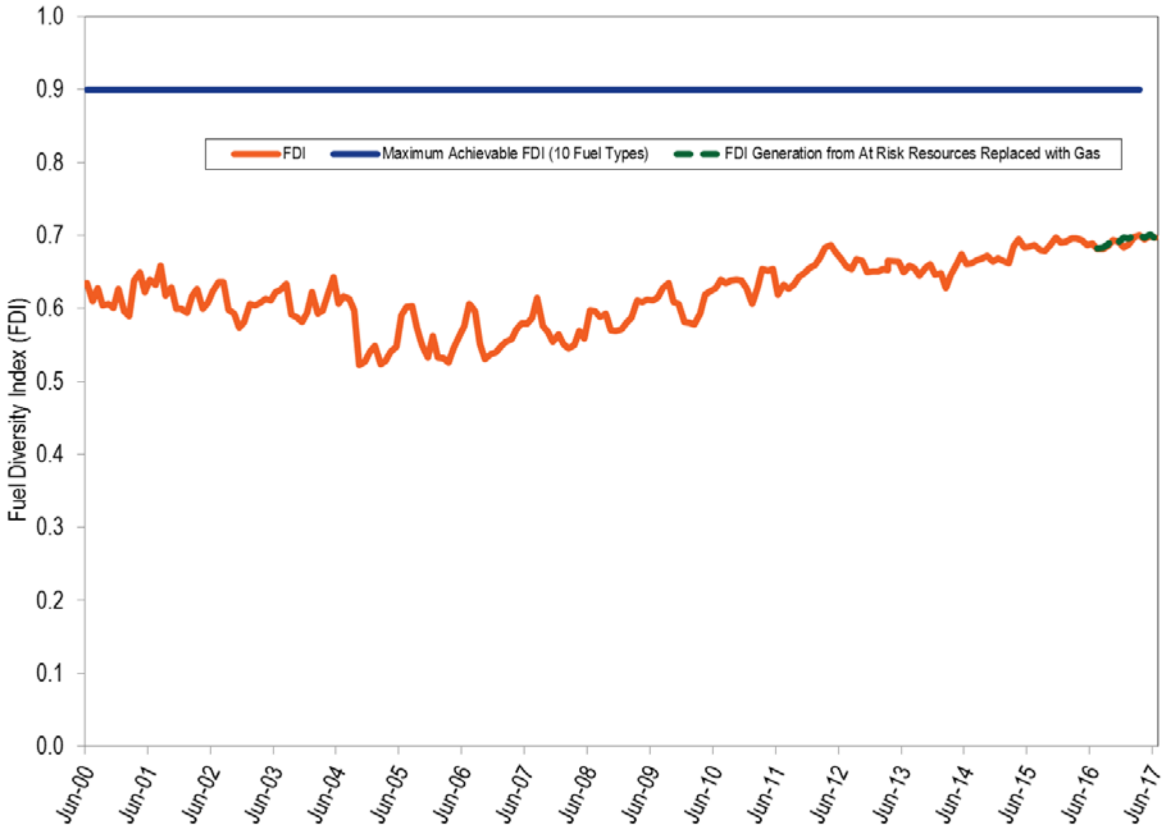
[36] See the *2016 State of the Market Report for PJM*, Volume 2, Appendix A, "PJM Geography" for an explanation of the expansion of the PJM footprint. The integration of the ComEd Control Area occurred in May 2004 and the integration of the AEP and Dayton control zones occurred in October 2004.

[37] See the *2016 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue, Units at Risk.

gas generation. The FDI_e under these assumptions would have increased in 10 of the 12 months with an average monthly increase of 0.3 percent over the actual FDI_e.

Figure 6 Fuel diversity index for PJM monthly generation: June 1, 2000 through June 30, 2017[38]



38 *2017 State of the Market Report for PJM, January through June,* Section 3: Energy Market, Figure 3-7 Fuel diversity index for PJM monthly generation: June 1, 2000 through June 30, 2017.

Table 14 PJM generation (By fuel source (GWh)): 2015 and 2016[39]

	2015 GWh	Percent	2016 GWh	Percent	Change in Output
Coal	284,757.4	36.2%	275,281.7	33.9%	(3.3%)
Bituminous	257,700.0	32.8%	241,050.2	29.7%	(6.5%)
Sub Bituminous	22,528.7	2.9%	28,949.7	3.6%	28.5%
Other Coal	4,528.6	0.6%	5,281.7	0.7%	16.6%
Nuclear	279,106.5	35.5%	279,546.4	34.4%	0.2%
Gas	183,650.7	23.3%	217,214.5	26.7%	18.3%
Natural Gas	180,948.7	23.0%	215,022.4	26.5%	18.8%
Landfill Gas	2,275.8	0.3%	2,176.2	0.3%	(4.4%)
Other Gas	426.3	0.1%	15.9	0.0%	(96.3%)
Hydroelectric	13,067.2	1.7%	13,686.8	1.7%	4.7%
Pumped Storage	4,660.2	0.6%	4,840.2	0.6%	3.9%
Run of River	6,736.3	0.9%	7,332.8	0.9%	8.9%
Other Hydro	1,670.8	0.2%	1,513.8	0.2%	(9.4%)
Wind	16,609.7	2.1%	17,716.0	2.2%	6.7%
Waste	4,365.1	0.6%	4,139.8	0.5%	(5.2%)
Solid Waste	4,175.4	0.5%	4,139.8	0.5%	(0.9%)
Miscellaneous	189.7	0.0%	0.0	0.0%	(100.0%)
Oil	3,276.2	0.4%	2,163.6	0.3%	(34.0%)
Heavy Oil	622.9	0.1%	270.6	0.0%	(56.6%)
Light Oil	1,122.0	0.1%	341.1	0.0%	(69.6%)
Diesel	163.8	0.0%	59.4	0.0%	(63.7%)
Gasoline	0.0	0.0%	0.0	0.0%	NA
Kerosene	413.0	0.1%	74.8	0.0%	(81.9%)
Jet Oil	0.0	0.0%	0.0	0.0%	NA
Other Oil	954.5	0.1%	1,417.7	0.2%	48.5%
Solar, Net Energy Metering	548.4	0.1%	1,019.4	0.1%	85.9%
Energy Storage	7.6	0.0%	15.7	0.0%	106.7%
Battery	7.6	0.0%	15.7	0.0%	106.7%
Compressed Air	0.0	0.0%	0.0	0.0%	NA
Biofuel	1,309.6	0.2%	1,760.3	0.2%	34.4%
Geothermal	0.0	0.0%	0.0	0.0%	NA
Other Fuel Type	0.0	0.0%	0.0	0.0%	NA
Total	786,698.5	100.0%	812,544.1	100.0%	3.3%

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39 *2016 State of the Market Report for PJM*, Volume 2, Section 7: Energy Market, Table 3-8 PJM generation (By fuel source (GWh)): 2015 and 2016.

Table 14 shows PJM generation by fuel source for 2015 and 2016. Nuclear and coal each constitute over one third of PJM supply. Natural gas supplies about one quarter, and oil, hydroelectric, solar, wind, waste, storage resources, and biofuels supply the other five percent.

I. The PJM June 2017 Report's Proposal to Allow Inflexible Units to Set Price Would Undermine Efficient Energy Market Functioning.

As part of its efforts to address a call for harmonization of state subsidies with RTO markets, PJM issued a report on June 15, 2017, titled "Energy Price Formation and Valuing Flexibility" (PJM Report).[40] The DOE Proposal recommends the PJM Report's inflexible unit pricing proposal as a potential solution.[41] In the report, PJM makes a number of claims about the results of the PJM energy market. The PJM Report claims that baseload, nuclear and coal, generation is undervalued in the market, that negative energy market offers have a pernicious effect in hastening the retirement of baseload generation, and that an increasing reliance on capacity market revenues, rather than energy market revenues, results in a bias in the markets.[42] The PJM Report provides no evidence supporting these claims. Rather than evaluating the supply and demand fundamentals of the market, the PJM Report's claims appear to reflect a desire to administratively alter the markets to favor nuclear and coal-fired generation. While not a direct subsidy, the PJM Report's proposal would impose significant additional cost on load to increase generator revenue, with a disproportionately large increase in revenues for nuclear and coal units.

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40 See PJM. "Energy Price Formation and Valuing Flexibility," (June 15, 2017) <http://www.pjm.com/~/media/library/reports-notices/special-reports/20170615-energy-market-price-formation.ashx> ("PJM Report").

41 *See* DOE Proposal at 46943, "After several years of fact finding and technical conferences, the record now supports energy price formation reform, such as the proposals laid out by PJM and others."

42 See PJM Report at 1.

It is not PJM's role to pick winners and losers in the market. PJM's role is to administer competitive markets that support the reliable transmission of power to load using a "decision-making process that is independent of control by any market participant or class of participants."[43] In this case, PJM held no open stakeholder discussion of the proposals in the report. PJM's largest participant, Exelon Corp., held a public discussion of the report on its second quarter 2017 earnings call. Exelon's Executive Vice President of Governmental and Regulatory Affairs stated that Exelon was "going to push very hard" to make sure that PJM would propose its pricing reforms to the Commission in early 2018 with implementation by summer 2018, an aggressive timeline that would not likely be met for a significant market pricing proposal through the PJM stakeholder process.[44] The PJM Report's proposal, which would impose significant costs on customers to the benefit of the owners of nuclear and coal-fired generation, is not the result of the process designed to support independent, deliberate decision making by PJM. The Market Monitor encourages PJM's use of the stakeholder process to explore ideas, to discuss options, and to allow all PJM stakeholders an opportunity to represent their interests. The Commission should make no directive that would hasten PJM energy market price formation changes.

1. The PJM Report Proposes Higher LMPs and a New Uplift Payment to Provide Additional Energy Market Revenues to Baseload Units.

PJM's June Report proposes a new and unprecedented calculation for setting prices in the energy market in stating that "PJM believes the range of resources eligible to set price should be expanded to include all units whose output is needed to serve load or control

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43 Order 2000: Regional Transmission Organizations, Federal Energy Regulatory Commission, 89 FERC ¶ 61,285 (December 20, 1999) at 152.

44 Exelon Q2 2017 Results – Earnings Call Transcript, Seeking Alpha (August 2, 2017), <https://seekingalpha.com/article/4093911-exelon-exc-q2-2017-results-earnings-call-transcript>.

transmission constraints in a given interval."[45] The PJM Report's proposal borrows a concept from the Commission's Fast Start Pricing NOPR, inappropriately extending the concept to the slowest starting units in the market.[46] Currently, the PJM LMP is determined by the cost of the next most costly single incremental MWh from an online resource needed to meet demand. The Fast Start NOPR seeks comments regarding the treatment of the average of short run costs for units that can start in less than 10 minutes as incremental costs, potentially including start costs and hourly no load costs in LMP. The rationale is that the entire output of the fast starting resource is marginal in the short run time frame of the market, because the market makes an economic decision to start the resource.[47] Even if the fast starting unit cannot change its output level up or down to provide the marginal MW, requiring a more flexible unit to reduce output to accommodate it, fast start pricing would allow the fast starting unit to determine the LMP. The true marginal unit that reduces its output and is available to provide the next MWh would no longer determine LMP. The PJM Report proposes to extend this concept well beyond the Commission's proposal and well beyond what any other RTO/ISO has done. The PJM Report would allow all resources to set the LMP in this way, even if the resource requires many hours or days to start and is unwilling or unable to reduce output or shut down based on market economics.[48]

The PJM Report's proposal would raise the cost to consumers of serving the same load in each market interval with no counteracting decrease to production costs. The proposal requires two energy market solutions for each five minute market interval: a

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45 PJM Report at 2.

46 Fast-Start Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators, 157 FERC ¶ 61,213 (December 15, 2016) ("Fast Start NOPR").

47 Fast Start NOPR at P8.

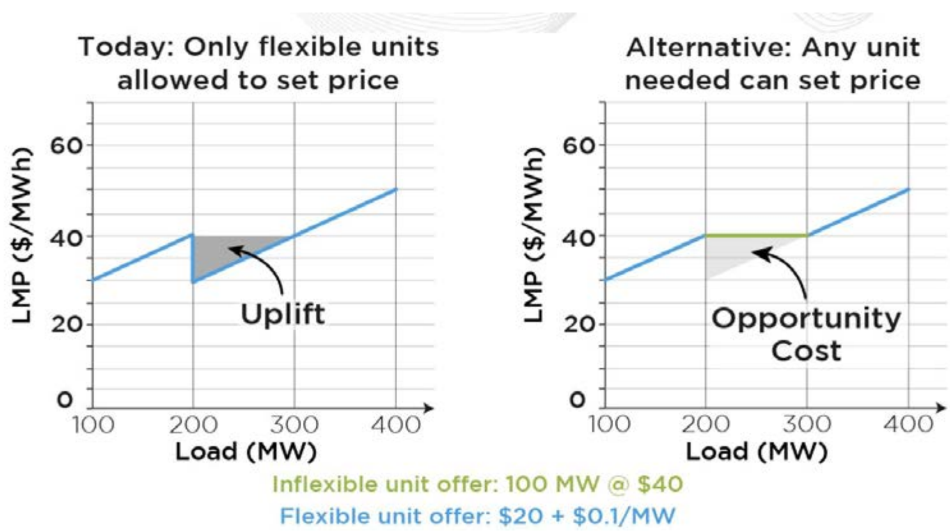
48 The proposal to extend the Fast Start NOPR pricing concept to all resources was not proposed by PJM in Docket RM17-3. Exelon included the proposal in its comments in the docket. *See* Comments of Exelon Corporation, Docket No. RM17-3 (February 28, 2017) at 3.

market dispatch solution, the same as the current market solution, and a pricing solution. The market dispatch solution produces the least cost dispatch of the system and prices that are consistent with that solution. The proposed pricing solution would raise the price to that of any inflexible unit that would provide the marginal MWh as if it were willing and able to change its output level, which it is not. The pricing solution is a fictitious solution that produces higher prices that are not consistent with the efficient dispatch of the market.

The inconsistency between pricing and dispatch creates a situation where the true marginal units have an incentive to raise their output level, because their marginal cost is less than the market price. The PJM Report proposes to provide these units with an economic incentive, through a new uplift payment, to maintain their efficient dispatch output level. The uplift payment would be equal to, at least, the opportunity cost of maintaining the dispatch level instead of following the economic pricing signal.

The PJM Report includes Figure 7 which illustrates the difference between the supply curve and payments for the dispatch solution and pricing solution.[49]

Figure 7 Comparison of price setting methods



[49] See PJM "Energy Price Formation and Valuing Flexibility," P 4, (June 15, 2017) <http://www.pjm.com/~/media/library/reports-notices/special-reports/20170615-energy-market-price-formation.ashx>

The dispatch solution on the left, currently used for both dispatch and pricing, results in a reduction in LMP at 200 MW of load, from $0 to $10 per MWh, and an uplift payment to the 100 MW inflexible unit required to serve load. The PJM Report's proposed pricing solution on the right results in a higher price of $40/MWh at 200 MW of load. The higher price is paid to all online generation, which averages near 100,000 MW for the PJM system.[50] The pricing solution also results in an opportunity cost uplift payment, as large as the original uplift payment, to the true marginal unit. The substantial cost increase to the market results from paying the higher price to the other 99,900 MW of supply.

Achieving the PJM Report's stated goal of valuing baseload generation through the proposed pricing mechanism would require PJM to include self scheduled nuclear units and coal units with minimum run times of several days in the set of inflexible units that set price. These baseload units are not part of PJM's daily economic unit commitment in the day-ahead market. The physical characteristics of the units, and in some cases the preferences of the unit operators, do not allow for economic determinations of whether the units' supply is optimal for the market. Much of the supply of such units is made available to PJM by the market participants regardless of price. Supply that is unwilling to change regardless of market price, regardless of the level of demand is never marginal. No economic theory supports allowing inflexible, baseload units to set price.

As a general principle, consumers should never have to pay for the recovery of costs that the system operator did not evaluate as part of its economic or reliability unit commitment processes. The PJM Report's proposal shares this characteristic with the DOE Proposal. Additionally, the PJM Report's proposal would create a windfall to all other generators operating when an uneconomic unit determines the energy price.

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50 The PJM average real-time cleared supply for 2016 is 95,054 MW. *See 2016 State of the Market Report for PJM*, Volume 2, Section 3: Energy Market, p. 107.

2. The PJM Report's Proposal to Value Inflexibility Undermines Market Incentives for Flexible Resources.

To allow inflexible units to set price, the PJM Report proposes divorcing the real-time five minute energy price from the five minute energy dispatch instruction. The pricing change removes the economic incentive for marginal units to follow the dispatch instruction. When a competitive marginal unit produces at the output level where price equals its short run marginal cost, it maximizes its profit. It only harms itself financially by producing at any other output level. Under the PJM Report's proposal, the marginal unit is paid as if it produces at the profit maximizing output level given the price set by the inflexible unit no matter its output level. The unit owner becomes indifferent to whether or not it follows the cost-minimizing dispatch instruction. No financial incentive supports the unit producing at the efficient dispatch level.

California ISO described the importance of setting five minute prices consistently with the five minute dispatch signal in its comments in opposition to the Fast Start NOPR.

> Not only must the CAISO focus on meeting peak load, but it now must also ensure sufficient ramping capability, both upwards and downwards, is available over relatively short periods to meet the sudden swings caused by variable energy resources. To this end, the CAISO has focused on resource adequacy enhancements to ensure that sufficient flexible resources are procured and offered into its market. This helps to ensure that flexible resources are compensated through capacity payments to provide the operational attributes needed to maintain reliable grid operations with higher levels of renewable resource penetration. The CAISO has also made significant investments to improve its real-time market to provide accurate price signals for resources to follow five-minute dispatch instructions… The CAISO is concerned that the Commission's proposed rule may undermine its efforts in

developing price signals and market products that incentivize five-minute dispatch ability.[51]

3. The PJM Report's Proposal Creates Adverse Economic Behavioral Incentives.

By breaking the relationship between the efficient economic dispatch and the price signal, the PJM Report's proposal would create new behavioral incentives in the market. In particular, higher prices would increase the incentive for generation to self schedule in the energy market. A self scheduled resource does not allow PJM to economically determine whether or not the resource operates. Instead, the market participant commits its resource to run. A self scheduled unit may self schedule its entire output or a designated output level above which it is subject to PJM dispatch. Self scheduling removes the economic unit commitment decision from PJM.

Table 15 shows that self scheduling is a common practice in the PJM energy market. More than half of all energy is provided by self scheduled units. Self scheduling is an efficient practice for resources with start times and minimum run times greater than the 24 hour time frame of the Day-ahead Market, such as nuclear units and large coal units, as long as the unit is economic on its longer operational time frame. Self scheduling can be inefficient for units that operate on a time frame within the market's daily framework.

Table 15 Day-ahead and real-time generation commitment status percent: 2016[52]

Energy Market	Self Scheduled (Must Run)	Self Scheduled (Dispatchable)	Pool Scheduled (Block Loaded)	Pool Scheduled (Dispatchable)	No Defined Status
Day-Ahead	32.5%	29.3%	3.4%	34.8%	0.0%
Real-Time	35.7%	24.9%	4.9%	34.2%	0.3%

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51 Comments of the California Independent System Operator Corporation, Docket No. RM17-3, (February 28, 2017) at 4-7.

52 *2016 State of the Market Report for PJM*, Section 4: Energy Uplift, Table 4-23 Day-ahead and real-time generation commitment status percent: 2016.

Under the current LMP approach, a competitively behaving market participant only self schedules its units when they are economic. If PJM raises the price for energy above the short run marginal cost of the marginal MW of supply, as suggested by the PJM Report's proposal, the financial incentives for self scheduling will become inconsistent with competitive behavior. The frequent self scheduling of generation should be expected to increase. If uncommitted resources would profit from self scheduling, additional generation would come online, lowering prices, requiring more uplift payments to flexible units that must reduce output and more lost opportunity cost payments. The result would undermine the PJM Report's attempt to raise energy prices. The result would undermine PJM's control of the system and further increase the cost of serving load.

4. Improvements to PJM Energy Market Price Formation would Support a More Efficient and Reliable Market.

PJM and the Market Monitor have discussed multiple options for improving energy market price formation that are consistent with and would not disrupt competitive markets. Improvements to better reflect local scarcity due to transmission constraints, system scarcity, and necessary reserves in prices would direct greater market value to the specific resources that support reliability. Some of these changes are already underway in the PJM stakeholder process, while others have made less progress.

PJM has continued to develop its approach to energy price formation. Subsequent to conversations with the Market Monitor and stakeholders, PJM has indicated that it may revise its focus away from the PJM Report's inflexible unit pricing proposal and toward scarcity pricing reform. PJM's ongoing efforts to improve price formation in the following areas have the ability to improve the short run efficiency of the PJM energy market as well as the long run price signals that determine efficient investment and decrease reliance on capacity market revenues and enhance reliability: scarcity pricing, pricing transmission scarcity, reserve products, combined cycle modeling, uplift payments, gas infrastructure, demand participation, and carbon pricing.

The Market Monitor encourages PJM to engage in open, public and transparent discussions with stakeholders about how to improve price formation for an efficient, competitive market.

a. Scarcity Pricing

In real-time wholesale electricity markets, demand is almost perfectly inelastic. Consumers generally do not have the ability to reduce demand in response to prices. As the amount of reserve capacity falls, the likelihood that the system operator will curtail load increases. Each MW quantity of reserve capacity has a marginal value related to the value of energy supply to consumers and the probability of a load curtailment.

The system operator constructs an operating reserve demand curve (ORDC) to define prices when it must reduce the quantity of reserve capacity in order to meet load. The ORDC should reflect the marginal value of reserves at each point along the demand curve, which is equal to the probability of a loss of load times the value of a loss of load.[53] The ORDC should cover all MW that the system operator requires to be available to ensure reliability. The comprehensive ORDC avoids unpriced actions, such as the commitment of additional generation to avoid shortages of reserves.

PJM currently uses an ORDC with two fixed price levels for two different MW ranges for reserves. Both PJM and the Market Monitor support reviewing the ORDC to determine whether the shape and the levels support efficient price formation in the energy market. The Market Monitor also recommends the introduction of more locational scarcity pricing as scarcity may exist at more local levels than the two broad areas now defined for scarcity pricing. More locational scarcity pricing will improve price formation and provide better price signals to generation and load.

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[53] *See* Hogan, William W., "Energy Scarcity Pricing Through Operating Reserves," Working Paper (April 25, 2013) <https://www.hks.harvard.edu/fs/whogan/Hogan_ORDC_042513.pdf>.

As part of reviewing scarcity pricing, PJM should review the relevance of the one in ten years reliability standard and its relevance to capacity procurement and impacts on energy market price formation.

b. Pricing Transmission Scarcity

In the PJM energy market security constrained economic dispatch, the objective is to minimize overall production cost while satisfying all applicable constraints, including transmission constraints. PJM's goal is to maintain the power flow at or below the relevant transmission line ratings.

LMP may, at times, be set by transmission penalty factors. When a transmission constraint is binding and there are no generation alternatives to resolve the constraint, system operators may allow the transmission limit to be violated. When this occurs, the shadow price of the constraint is set by transmission penalty factors. The shadow price directly affects the LMP. Transmission penalty factors are administratively determined and can be thought of as a form of locational scarcity pricing.

Transmission penalty factors should be stated explicitly and publicly and applied without discretion. Penalty factors should be set high enough so that they do not act to suppress prices based on available generator solutions. But rather than permit the transmission penalty factor to set the shadow price when line limits are violated, PJM uses a procedure called constraint relaxation logic to prevent the penalty factors from directly setting the shadow price of the constraint. The result is that the transmission penalty factor does not directly set the shadow price. The details of PJM's logic and practice are not entirely clear.

The Market Monitor believes that, in order to improve price formation, it is important to have clear, transparent and unambiguous guidelines on all aspects of the use of transmission penalty factors in setting prices because transmission penalty factors directly affect prices and are a form of locational scarcity pricing.

c. Evaluation of Reserve Products

Use of the ORDC should complement the procurement of reserve capacity by PJM in the energy market. PJM, FERC, and NERC determine which resource attributes are necessary to maintain real-time grid reliability. PJM uses reserve products to define those attributes and to allow market participants to competitively supply them. PJM operators also commit additional resources to address other reliability needs encountered during real time market operation. If the real-time reliability needs are not met by an existing reserve product, PJM should identify the specific needs and create a product to allow market pricing to reflect the necessary operator actions. In particular, the Market Monitor recommends that PJM replace the current Day-Ahead Scheduling Reserve Market with a real-time secondary reserve product that is available and dispatchable in real time.

d. Combined Cycle Modeling

The current modeling of combined cycle plants in PJM and other RTO/ISOs does not capture the full flexibility of combined cycle plants across all the potential configurations available for combined cycles. Improved modeling and pricing for the flexible combined cycle plants would provide better incentives for flexibility and reduce the need for reliance on inflexible units.

e. Reductions to Uplift Payments

PJM should consider how to provide incentives for units to be flexible and reduce incentives to be inflexible. Units should not be paid uplift based on inflexible parameters that result from decisions about whether to invest in units. Units should be paid uplift based on the parameters of the reference unit used in establishing the cost of new entry in the capacity market.

f. Gas infrastructure reliability

As part of ensuring that a grid that is more reliant on gas-fired resources continues to be reliable, PJM should continue to evolve its approaches to evaluating reliability and extend those to gas infrastructure. Use of transmission planning and reliability concepts should be applied to the gas infrastructure. If warranted by reliability concerns, the use by the Commission of an ISO construct in the gas market to enhance planning for reliability across gas pipelines, to enhance interoperability of pipelines with power generators and to enhance interoperability across gas pipelines should be explored.

g. Demand side

The role and treatment of demand side resources in PJM should be evaluated for improvements. Demand side resources are a very significant and important part of the resource mix and the role of demand side resources in the energy market and capacity market should be redefined to permit customers the maximum flexibility to respond to energy and capacity prices and to benefit immediately from that response.

h. Carbon Pricing

If society determines that carbon is a pollutant, the most efficient way to address the issue would be a carbon price. A carbon price would change energy market pricing and provide an incentive for the most efficient approaches to reducing carbon output.

II. COMMUNICATIONS

Pursuant to 18 C.F.R. § 385.203(b)(3), the Market Monitor designates the following persons as those to receive all notices and communications with respect to this proceeding:

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III. CONCLUSION

The Market Monitor respectfully requests that the Commission afford due consideration to this pleading as the Commission resolves the issues raised in this proceeding.

Respectfully submitted,

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Dated: October 23, 2017