UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	Docket No. ER18-1314-003
Calpine Corporation, Dynegy Inc., Eastern Generation, LLC, Homer City Generation, L.P., NRG Power Marketing LLC, GenOn Energy Management, LLC, Carroll County Energy LLC, C.P. Crane LLC, Essential Power, LLC, Essential Power OPP, LLC, Essential Power Rock Springs, LLC, Lakewood Cogeneration, L.P., GDF SUEZ Energy Marketing NA, Inc., Oregon Clean Energy, LLC and Panda Power Generation Infrastructure Fund, LLC	)	Docket Nos. EL16-49-000, EL18-178-000 (Consolidated)
v.	)	
PJM Interconnection, L.L.C.	)	

COMMENTS OF THE INDEPENDENT MARKET MONITOR FOR PJM

Pursuant to Rule 211 of the Commission's Rules and Regulations,[1] Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor ("Market Monitor") for PJM Interconnection, L.L.C. ("PJM"),[2] submits these comments responding to the filing submitted by PJM Interconnection, L.L.C. ("PJM") on March 18, 2020 ("March 18th

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1 18 CFR § 385.211 (2019).

2 Capitalized terms used herein and not otherwise defined have the meaning used in the PJM Open Access Transmission Tariff ("OATT"), the PJM Operating Agreement ("OA") or the PJM Reliability Assurance Agreement ("RAA").

Filing") in compliance with the order issued December 19, 2019 ("December 19th Order"), in this proceeding.[3]

I. COMMENTS

A. Default Net Cost of New Entry ("CONE") and Avoidable Cost Rates ("ACRs")

Table 1 compares PJM's proposed MOPR floor prices with the Market Monitor's proposed floor prices.

Table 1 Comparison of PJM and Market Monitor Net CONE MOPR floor prices[4] [5] [6]

	$/MW-Day ICAP					
	Gross CONE		E&AS		Default MOPR Floor	
Resource Type	PJM	IMM	PJM	IMM	PJM	IMM
Nuclear	$2,000	$3,790	$517	$689	$1,483	$3,101
Coal	$1,068	$1,593	$43	$38	$1,025	$1,555
Combined Cycle	$320	$320	$168	$202	$152	$118
Combustion Turbine	$294	$333	$48	$126	$246	$207
Solar PV (Tracking)	$290	$386	$185	$128	$105	$258
Solar PV (Fixed)	$271	$668	$117	$128	$154	$540
Onshore Wind	$420	$620	$240	$201	$180	$419
Offshore Wind	$1,155	$1,946	$337	$311	$818	$1,636
Battery Storage (4 hr)	$532	$990	$116	$124	$416	$866
Load Demand Response	$55		-	-	$55	
Gen Demand Response	$254	$465	$0	$23	$254	$442
Energy Efficiency	$64		-	-	$64	

3 *PJM Interconnection, L.L.C., et al.*, 169 FERC ¶ 61,239.

4 The solar PV (tracking) installation reflects PJM and the Market Monitor values for a 150 MW single axis tracking installation. The solar PV (fixed) reflects PJM values for a 100 MW fixed installation and the Market Monitor values for a 10 MW fixed installation as presented in the *2019 State of the Market Report for PJM*, Section 7: Net Revenue.

5 The onshore wind installation reflects PJM values for a 50 MW installation and the Market Monitor values for a 100 MW installation as presented in the *2019 State of the Market Report for PJM*, Section 7: Net Revenue.

6 Market Monitor E&AS values for nuclear, coal, combined cycle and combustion turbine values are the three year average 2017-2019 new entrant E&AS across all zones plus the associated ancillary service revenue. *See 2019 State of the Market Report for PJM*, Section 7: Net Revenue. Tables 7-3, 7-9, 7-11, 7-13 and 7-15.

Table 2 shows the differences between PJM and Market Monitor Gross CONE, Energy and Ancillary Services ("E&AS") offset, and the default MOPR floor. The table entries are the Market Monitor values minus the PJM values. A positive value means that the Market Monitor value is higher than the PJM value and a negative value means that the Market Monitor value is lower than the PJM value.

Table 2 Differences between PJM and Market Monitor values for a new entrant unit

	Differences $/MW-Day ICAP		
Resource Type	Gross CONE	E&AS	Default MOPR Floor
Nuclear	$1,790	$172	$1,618
Coal	$525	($5)	$530
Combined Cycle	($0)	$34	($34)
Combustion Turbine	$39	$78	($39)
Solar PV (Tracking)	$96	($57)	$153
Solar PV (Fixed)	$397	$11	$386
Onshore Wind	$200	($39)	$239
Offshore Wind	$791	($26)	$818
Battery Storage (4 hr)	$458	$8	$450
Load Demand Response	NA	NA	NA
Gen Demand Response	$211	$23	$188
Energy Efficiency	NA	NA	NA

Table 3 presents the primary reasons for the differences between the PJM and Market Monitor Gross CONE values.

Table 3 Major differences between PJM and Market Monitor Gross CONE values

Resource Type	Differences in Gross CONE	
	PJM	IMM
Solar PV (Tracking)	150 MW No regional variation Excludes standard capital cost line items Excludes standard O&M line items	150 MW Located in NJ Includes standard capital cost line items Includes standard O&M line items
Solar PV (Fixed)	100 MW Calculated by applying a 0.94 fixed-to-tracking cost ratio to the CapEx and fixed O&M values used for solar PV (tracking)	10 MW Located in NJ Includes standard capital cost line items Includes standard O&M line items
Onshore Wind	50 MW No regional variation Excludes standard capital cost line items Excludes standard O&M line items	100 MW Located in COMED Includes standard capital cost line items Includes standard O&M line items
Offshore Wind	400 MW	300 MW
Battery Storage (4 hr)	200 MWh Levelized over 15 years	20 MWh Levelized over 20 years
Gen Demand Response	0.5 MW	2 MW

B. Gross Cost of New Entry ("CONE") Values

PJM has relied primarily on the U.S. Energy Information Agency ("EIA") for Gross CONE values for solar and wind. PJM used Brattle's adjusted NEI data for nuclear. PJM used Brattle data for CTs and CCs. PJM does not appear to have examined the method used to build up the solar and wind costs in sufficient detail. Brattle's adjustments to the NEI data are unsupported. Brattle's data on CTs and CCs are overstated for reasons explained in the Quadrennial Review filings.[7]

1. Solar Costs

PJM's Gross CONE significantly understates the cost to build a new entrant solar installation. PJM includes EIA cost estimates of a 150 MW new entrant solar unit with tracking technology.[8] The Market Monitor uses the same technology for the solar tracking

7 *See* Docket No. ER19-105-000.

8 EIA. Capital Costs and Performance Characteristics to Utility Scale Power Generating Technologies, January 2020. Case 24. <https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf>.

technology but recommends that PJM apply the location adjustment for Gross CONE specified in Table 1-24 of the EIA report used by PJM for a more accurate regional Gross CONE. PJM should also include the standard capital cost line items and expenses that are excluded from EIA's cost build up.

PJM should account for regional variation in solar costs. The difference in installed cost varies within the PJM footprint from $1,252/kW in Cincinnati, Ohio, to $1,486/kW in Philadelphia, Pennsylvania, as a result of differences in union and non-union labor rates, property tax rates and property lease rates.

The Market Monitor recommends that PJM account for the following standard capital cost line items not included in the EIA new entrant solar installation cost buildup: Electric Interconnection and System Upgrades; Initial Spare Parts Inventory; Plant Startup Expenses; One Year Construction Period Land Lease; Development Expenses; Legal and Accounting Fees; Financing and Closing Fees; Interest During Construction; and EIS, Zoning and Plant Use Permits.

The EIA O&M cost estimate also does not include industry standard line item expenses. The Market Monitor recommends that PJM account for industry standard line item expenses including: insurance, general and administrative costs; and land owner property tax reimbursement. EIA does carry a property lease line item expense but it appears to be understated for the nearly 500 acres required for a 150 MW solar project. The 150 MW solar installation requirement for 500 acres makes it unlikely that such a large facility would be sited in the eastern zones.

The Market Monitor's Gross CONE for tracking solar is based on the same source EIA data with adjustments for regional cost variation, adding standard line items for capital costs and expenses to the capital cost of the EIA solar installation. The result is to increase the cost of building a new tracking solar unit in New Jersey from PJM's estimate of $290/MW-day ICAP to $386/MW-day.

Use of the 150 MW solar unit size understates the default MOPR floor for general applicability in PJM. A 150 MW solar unit is too large for a reference unit because it would be difficult for an installation of this size to be built in many of the eastern PJM zones. Larger units have lower costs per MW than smaller units. Units with lower costs than the reference unit have the unit specific MOPR price floor option.

To calculate the Gross CONE value for the reference 100 MW fixed solar unit, PJM simply applied a 0.94 ratio of fixed to tracking costs to the capital costs and fixed O&M used for the tracking unit.

The Market Monitor developed Gross CONE for a 10 MW solar unit from the ground up based on supplier quotes and standard new entrant analysis.

2. Onshore Wind Costs

PJM's Gross CONE significantly understates the cost to build a new entrant onshore wind installation. The PJM onshore wind unit is a 50 MW installation using EIA costs.[9] The Market Monitor recommends that PJM apply the location adjustment specified in the EIA report Table 1-21 for a more accurate regional Gross CONE and include the standard capital cost line items and expenses excluded from EIA's cost build up.

PJM should account for regional variation in costs. The difference in installed cost varies within the PJM footprint from $1,655/kW in Cincinnati, Ohio, to $1,743/kW in Newark, New Jersey, as a result of differences in union and non-union labor rates and property tax rates and property lease rates.

The Market Monitor recommends that the Gross CONE include the standard capital cost line items not included in the EIA costs, similar to the solar installation.[10]

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9 EIA. Capital Costs and Performance Characteristics to Utility Scale Power Generating Technologies, February 2020. Case 21. <https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf>.

10 Line items excluded from the EIA capital cost include: electric interconnection and system upgrades; BOP equipment spares; owner's contingency; financed startup expenses; land reservation payment; development expenses; legal and accounting fees; financial/closing fees; interest during construction; decommissioning bond costs; land lease upfront payment; EIS, zoning and plant use permits.

The Market Monitor recommends that the Gross CONE include industry standard line item expenses not included in the EIA costs such as insurance, general and administrative, O&M management fee, property tax, and property lease.

Making adjustments for regional cost variation and adding standard line item expenses to the capital cost of the EIA wind installation would increase the cost of building a 50 MW onshore wind installation in Pennsylvania by $28 million, or $184/kW installed cost. Making the additional adjustments to fixed O&M of a 50 MW onshore wind installation in Pennsylvania would increase Gross CONE by $94/MW-day, from $420/MW-day ICAP to $514/MW-day ICAP.[11]

The Market Monitor Gross CONE value of $620/MW-day ICAP was developed using a ground up approach via supplier quotes and standard new entrant analysis.

3. Offshore Wind Costs

PJM's Gross CONE value for a new offshore wind facility is understated. The PJM offshore wind unit is a 400 MW ICAP wind facility. The Market Monitor offshore wind unit is a 300 MW ICAP wind facility. Both units are of a similar size and are located off the coast of New Jersey. The primary difference in the Gross CONE of the two units is the engineering, procurement and construction ("EPC") cost. The Market Monitor EPC capital cost developed by Stantec was $6,762/kW versus $4,227/kW for the EIA EPC estimate.

The only offshore wind facility installed and operating off the U.S. coast is the Block Island Wind Farm, a 30 MW, 5 turbine installation that began operating in 2016. The current offshore wind installations being considered are larger and more complex than the Block

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[11] The Market Monitor value of $515/MW-Day is calculated by taking the EIA cost buildup for a 50 MW installation and adding the cost components excluded from the EIA capital costs and O&M costs. The Market Monitor value of $620/MW-Day is for a 100 MW installation as presented in the *2019 State of the Market Report for PJM*, Section 7: Net Revenue.

Island installation, which cost $290 million, or $9,667/kW.[12] There are currently several offshore wind projects in various stages of development off the east coast of the U.S. and there is a significant amount of uncertainty surrounding construction factors, including water depth and conditions, turbine loading and rotor speed, lease area sizes, supply chain and infrastructure for equipment fabrication and transportation.

The Market Monitor recommends that PJM apply the EIA location adjustment specified in the EIA report Table 1-22 for a more accurate regional Gross CONE, in addition to including additional standard capital cost line items and expenses excluded from EIA's cost.[13]

The Market Monitor also recommends that PJM calculate Net CONE only for zones which could feasibly build an offshore wind installation. PJM's filing includes offshore wind values for zones where offshore wind is not feasible, such as PENELEC.[14]

For offshore wind of the scale reviewed, there is so much uncertainty that only unit specific costs should be the basis for offshore wind MOPR floors. If the Commission wants to set a default floor, the Market Monitor recommends $1,946/MW-Day ICAP, as a reasonable MOPR floor value.

4. Demand Response (Generation Backed)

PJM uses data from a Lazard report as the basis for the MOPR offer floor for generation backed demand response.[15] The MOPR price for demand resources that use

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12 Providence Journal, "Deepwater Wind completes financing for Block Island wind farm," (March 2, 2015) Project cost of $290 million is based on public data. <*https://www.providencejournal.com/article/20150302/NEWS/150309845/13942/BUSINESS*>.

13 Line items excluded from the EIA capital cost include: electric interconnection and system upgrades; BOP equipment spares; owner's contingency; financed startup expenses; land reservation payment; development expenses; legal and accounting fees; financial/closing fees; interest during construction; decommissioning bond costs; land lease upfront payment; EIS, zoning and plant use permits.

14 March 18th Filing Appendix A.

behind the meter generation to reduce load should have the same costs as the same generation technology in front of the meter. The Market Monitor recommends calculating unit specific generator costs for generation backed demand response rather than assume a value.

5. Demand Response (Load Backed)

PJM proposes Load DR Gross CONE of $53.32/MW-Day based on three year average of offers. PJM asserts that load backed DR does not have any avoidable costs. For this reason PJM proposes Load DR Gross and Net ACR of $0/MW-Day.

The Market Monitor recommends that load backed DR Gross ACR be set equal to load backed DR Gross CONE because there is no meaningful difference between initial and avoidable costs for load backed DR. The cost of DR is the cost of taking the actions to interrupt and not the cost of creating the capability to interrupt. This is consistent with Demand Resources' offer behavior.

6. EE Costs

PJM proposes that the Energy Efficiency Resource MOPR Floor Offer Price remain unchanged between Quadrennial Reviews. The Brattle Report attempts to calculate values for EE resources, but the assumptions and exclusions of programs demonstrate the complexity of picking a value for Energy Efficiency resources.[16] The Net CONE proposed in the Brattle Report varies from -$76/MW-day to $256/MW-day.[17] Picking a single value to use between quadrennial reviews will not accurately estimate any participant's Net CONE. PJM should require unit specific costs for each program to ensure an accurate cost. There

15 *Id*. at 59.

16 *Gross Avoidable Cost Rate for Existing Generation and Net Cost of New Entry for New Energy Efficiency*, The Brattle Group, Table 11: EE Programs by Utility.

17 *Id.* Table 15: Net CONE of EE Programs by Utility.

must be robust M&V to accurately measure the impact of the EE resources. The Market Monitor recommends that EE values be unit specific in order to accurately reflect the costs of the EE program.

C. Avoidable Cost Rate (ACR) Values

With the exception of nuclear ACR values, PJM ACR reflects retirement ACR values and excludes major maintenance costs. With the exception of nuclear ACR, the Market Monitor values reflect mothball ACR values and exclude major maintenance costs where defined. Renewable resource ACR costs include all costs. There are differences between PJM and the Market Monitor on net ACR for single unit nuclear, coal and DR.

Table 4 Comparison of PJM and Market Monitor ACR MOPR floor prices in $/MW-Day ICAP[18] [19]

	$/MW-Day ICAP					
	Gross ACR		E&AS		Default MOPR Floor	
Resource Type	PJM	IMM	PJM	IMM	PJM	IMM
Nuclear - single	$697	$754	$487	$602	$210	$152
Nuclear - multiple	$445	$525	$517	$519	$0	$6
Coal	$80	$105	$43	$38	$37	$67
Combined Cycle	$56	$25	$168	$202	$0	$0
Combustion Turbine	$50	$22	$48	$126	$2	$0
Solar PV (Tracking)	$40	$21	$185	$128	$0	$0
Solar PV (Fixed)	$40	$14	$117	$128	$0	$0
Onshore Wind	$83	$95	$240	$201	$0	$0
Offshore Wind		$234	$337	$311		$0
Battery Storage (4 hr)			$116			
Load Demand Response	$0				$0	Net CONE
Gen Demand Response	$3	$47	$0	$23	$3	$24
Energy Efficiency	$0				$0	

Table 5 shows the differences between PJM and Market Monitor Gross ACR, E&AS offset, and the Default MOPR Floor. The table entries are the Market Monitor values minus

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18 PJM Gross ACR excludes major maintenance. The Market Monitor Gross ACR excludes major maintenance for all resource types except solar tracking, solar fixed, onshore wind and offshore wind.

19 The Market Monitor E&AS for all unit types except nuclear are short run marginal costs.

the PJM values. A positive value means that the Market Monitor value is higher than the PJM value and a negative value means that the Market Monitor value is lower than the PJM value.

Table 5 Differences between PJM and Market Monitor values for an existing unit

	Differences $/MW-Day ICAP		
Resource Type	Gross ACR	E&AS	Default MOPR Floor
Nuclear - single	$57	$115	($58)
Nuclear - multiple	$80	$2	$6
Coal	$25	($5)	$30
Combined Cycle	($31)	$34	$0
Combustion Turbine	($28)	$78	($2)
Solar PV (Tracking)	($19)	($57)	$0
Solar PV (Fixed)	($26)	$11	$0
Onshore Wind	$12	($39)	$0
Offshore Wind	NA	($26)	NA
Battery Storage (4 hr)	NA	NA	NA
Load Demand Response	NA	NA	NA
Gen Demand Response	$44	$23	$21
Energy Efficiency	NA	NA	NA

Table 6 presents the primary reasons for the differences between the PJM and Market Monitor Gross ACR values.

Table 6 Major differences between PJM and Market Monitor Gross ACR values

	Differences in ACR	
Resource Type	PJM	IMM
Nuclear - single	Excludes major maintenance E&AS includes $9.02/MWh of fuel, variable O&M, and maintenance costs	Excludes capital expenditures as a proxy for major maintenance E&AS does not account for any short run marginal costs
Nuclear - multiple	Excludes major maintenance E&AS includes $7.66/MWh of fuel, variable O&M, and maintenance costs	Excludes capital expenditures as a proxy for major maintenance E&AS does not account for any short run marginal costs
Coal		Calculated a percent avoidable of all fixed O&M line items

1. Nuclear Costs

The Market Monitor E&AS for nuclear units is the 2021 average of the single or multiple plants from Table 7 below. The analysis of nuclear plants includes publicly available data on energy market prices, capacity prices, and an estimate of annual avoidable costs and incremental capital expenditures from the Nuclear Energy Institute (NEI) based on NEI's average across all U.S. nuclear plants.[20] [21] The LMPs are based on forward prices with a basis adjustment for the specific plant locations.[22] The 2020 energy prices include actual day-ahead market prices through March 31, 2020, and forward prices for April through December 2020. Gross ACR is NEI total cost including fuel and operating cost, excluding capital expenditures as a proxy for fixed VOM given that NEI does not provide a breakout of major maintenance, multiplied by the 2019 class average capacity factor for nuclear units of 93.3 percent.[23] NEI capital expenditures are likely to be a conservatively low estimate of major maintenance expense.

The Market Monitor MOPR price floor for single unit nuclear in the table is the average of the 2021 Net ACR for single units from Table 7 below.[24] [25] The Market Monitor MOPR price floor for multiple unit nuclear is the average of the 2021 Net ACR for multiple units.

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20 Operating costs from: Nuclear Energy Institute (September, 2019). "Nuclear Costs in Context," <*https://www.nei.org/resources/reports-briefs/nuclear-costs-in-context*>. Individual plant results may vary from the average due to factors including location, local labor costs, the timing of refueling outages, cost management practices, and other unit specific factors.

21 The NEI costs for Hope Creek and Salem plants were both treated as those associated with a two unit configuration because all three units are located in the same area.

22 Forward prices on April 1, 2020. Forward prices are reported for PJM trading hubs which are adjusted to reflect the historical differences between prices at the trading hub and prices at the relevant plant locations. The basis adjustment is based on 2019 data.

23 Class average capacity factor is from *2019 State of the Market Report for PJM, Vol. 2,* Section 5: Capacity Market.

24 This table is a combination of Table 7-23 and Table 7-24 from the *2020 Quarterly State of the Market Report for PJM: January through March*, Section 7: Net Revenue.

25 Forward prices on April 2, 2020. Forward prices are reported for PJM trading hubs which are adjusted to reflect the historical differences between prices at the trading hub and prices at the relevant plant locations. The basis adjustment is based on 2019 data. The 2020 energy prices include actual day-ahead market prices through March 31, 2020, and forward prices for April through December 2020.

Table 7 Forward price in PJM energy markets, annual costs, and implied Net ACR

	ICAP	Average Forward LMP ($/MWh)			Ancillary Revenue ($/MWh)	2018 NEI Costs ($/MWh)			Net ACR Excluding Capital ($/MWh)			Net ACR Excluding Capital ($/MW-Day)		
	(MW)	2020	2021	2022	Reactive	Fuel	Operating	Capital	2020	2021	2022	2020	2021	2022
Beaver Valley	1,808	$21.07	$26.38	$25.90	$0.24	$6.01	$17.44	$5.62	$2.14	$0.00	$0.00	$47.96	$0.00	$0.00
Braidwood	2,337	$18.95	$23.66	$23.23	$0.24	$6.01	$17.44	$5.62	$4.26	$0.00	$0.00	$95.31	$0.00	$0.00
Byron	2,300	$18.18	$22.68	$22.27	$0.21	$6.01	$17.44	$5.62	$5.06	$0.56	$0.97	$113.28	$12.60	$21.64
Calvert Cliffs	1,708	$21.99	$27.57	$27.07	$0.20	$6.01	$17.44	$5.62	$1.26	$0.00	$0.00	$28.32	$0.00	$0.00
Davis Besse	894	$21.05	$26.31	$25.83	$0.24	$5.84	$27.82	$8.34	$12.37	$7.11	$7.58	$276.93	$159.16	$169.83
Dresden	1,797	$19.28	$24.16	$23.72	$0.32	$6.01	$17.44	$5.62	$3.85	$0.00	$0.00	$86.12	$0.00	$0.00
Hope Creek	1,172	$18.31	$23.71	$23.30	$0.43	$6.01	$17.44	$5.62	$4.71	$0.00	$0.00	$105.48	$0.00	$0.00
LaSalle	2,271	$18.82	$23.54	$23.11	$0.18	$6.01	$17.44	$5.62	$4.45	$0.00	$0.16	$99.58	$0.00	$3.59
Limerick	2,242	$18.36	$23.78	$23.37	$0.14	$6.01	$17.44	$5.62	$4.96	$0.00	$0.00	$110.95	$0.00	$0.00
North Anna	1,892	$21.61	$27.15	$26.66	$0.17	$6.01	$17.44	$5.62	$1.68	$0.00	$0.00	$37.53	$0.00	$0.00
Peach Bottom	2,347	$17.85	$22.98	$22.58	$0.28	$6.01	$17.44	$5.62	$5.31	$0.19	$0.59	$118.95	$4.24	$13.16
Perry	1,240	$21.27	$26.94	$26.46	$0.24	$5.84	$27.82	$8.34	$12.15	$6.48	$6.96	$272.01	$145.08	$155.92
Quad Cities	1,819	$16.70	$21.51	$21.14	$0.18	$6.01	$17.44	$5.62	$6.58	$1.76	$2.13	$147.28	$39.41	$47.71
Salem	2,328	$18.30	$23.73	$23.32	$0.12	$6.01	$17.44	$5.62	$5.02	$0.00	$0.00	$112.51	$0.00	$0.07
Surry	1,676	$20.77	$26.37	$25.90	$0.17	$6.01	$17.44	$5.62	$2.51	$0.00	$0.00	$56.22	$0.00	$0.00
Susquehanna	2,520	$17.19	$21.81	$21.43	$0.28	$6.01	$17.44	$5.62	$5.98	$1.36	$1.74	$133.91	$30.40	$38.94

D. Definition of Net Revenues

1. Net Revenues for New Entry Generation Capacity Resources

PJM E&AS is based on three year historical values. The Market Monitor E&AS for nuclear is based on forward prices with a basis adjustment for the specific plant locations.[26]

The Market Monitor E&AS for combined cycles is calculated for a new CC plant economically dispatched by PJM. It is assumed that the CC plant had a minimum run time of four hours. The unit is first committed day ahead in profitable blocks of at least four hours, including start costs. If the unit is not already committed day ahead, it is run in real time in standalone profitable blocks of at least four hours, or any profitable hours bordering the profitable day-ahead or real-time block. The Market Monitor's calculation is more reflective of the way in which actual units are dispatched and operated than PJM's rigid and unrealistic assumptions.

26 Forward prices on April 1, 2020. Forward prices are reported for PJM trading hubs which are adjusted to reflect the historical differences between prices at the trading hub and prices at the relevant plant locations. The basis adjustment is based on 2019 data.

Table 8 presents the primary reasons for the differences between the PJM and Market Monitor E&AS values.

2. Net Revenues for Cleared Generation Capacity Resources

The Market Monitor agrees with PJM that projected revenues should be allowed as an option for resources requesting a resource specific exception. The Market Monitor recommends that PJM strengthen the language regarding price forecasts to specify that the price forecasts will rely on publicly available forward curves that reflect market values for future prices and that if consultant reports are used that the consultants provide evidence that they provide identical forecasts to buyers and sellers in the industry.

Table 8 Major differences between PJM and Market Monitor E&AS values

Resource Type	Differences in E&AS	
	PJM	IMM
Nuclear - single	E&AS includes $9.02/MWh of fuel, variable O&M, and maintenance costs E&AS based on 3 year historical operations	E&AS sets short run marginal costs equal to zero E&AS based on 2021 forward bus prices
Nuclear - multiple	E&AS includes $7.66/MWh of fuel, variable O&M, and maintenance costs E&AS based on 3 year historical operations	E&AS sets short run marginal costs equal to zero E&AS based on 2021 forward bus prices
Combined Cycle	Dispatched during peak hours only	Economically dispatched first in the DA market, then in the RT market with a minimum run time for 4 hours

3. Net Revenues for Demand Resources

Demand response revenues consist of E&AS and avoided retail energy costs. The calculation of E&AS revenues is consistent with all resources. Demand response participation in the E&AS markets is a small component of the total revenue for demand resources. E&AS payments to demand resources in 2019 were $6.2 million, or 1.3 percent, of all demand response revenue. Capacity payments and emergency energy payments to demand resources in 2019 were $484.4 million, or 98.7 percent, of all demand response revenue. Demand resources do not participate frequently in the energy and ancillary service markets. Demand resources also avoid paying for retail energy when reducing load. The retail savings depend on the individual customer's contract with the supplier.

Demand response costs consist of short run marginal costs. Generation backed demand response has the same costs as front of the meter generation. Load backed demand response costs consist of any verifiable costs for reducing load. The Value of Lost Load (VOLL) should not be used as an offset for calculating the MOPR floor price. Reductions of load, and the associated reduction of output, in one hour can be made up in another hour. The value of lost load is not a source of revenue or an offset to demand response resources.

E. Asset Life Ban

The December 19th Order states (at P 162):

> 162. We share intervenors' concerns that PJM's proposed language leaves a loophole whereby a resource may not be eligible for a State Subsidy at the time of the capacity market qualification process, but may become eligible for such a subsidy, and accept it, before or during the relevant delivery year. We therefore direct PJM to include in its compliance filing a provision stating that if an existing resource claims the Competitive Exemption in a capacity auction for a delivery year and subsequently elects to accept a State Subsidy for any part of that delivery year, then the resource may not receive capacity market revenues for any part of that delivery year. We also direct PJM to include in its compliance filing a provision stating that if a new resource claims the Competitive Exemption in its first year, then subsequently elects to accept a State Subsidy, that resource may not participate in the capacity market from that point forward for a period of years equal to the applicable asset life that PJM used to set the default offer floor in the auction that the new asset first cleared. We find that, absent this change, PJM's proposed language would allow gaming and incent the creation of subsidy programs timed to avoid the qualification window.

In the March 18th Filing, PJM included an exception to this rule under which a Capacity Market Seller of a Cleared Capacity Resource that uses the competitive exemption and had accepted a State Subsidy or subsequently accepts a State Subsidy can avoid the associated consequence of forfeiting RPM revenues if "…it can demonstrate that it would have cleared in the relevant RPM Auction under an offer consistent with the resource-specific exception process outlined above in Section 5.14(h)(3)."[27] Reliance on the competitive exemption for an RPM Auction properly constitutes a commitment to participate in PJM markets on a competitive basis and not to accept subsidies during the relevant delivery year. Allowing such an exception when participants know the specific level of subsidy that would be excepted invites strategic behavior. No such exception applies to a New Entry Capacity Resources and existing resources should be treated consistently under the rules. The Market Monitor recommends that there be no exception to the Commission's directive.

F. Resource Specific Review

1. Asset Life

PJM proposes to allow capacity market sellers to use an alternative asset life up to 35 years in the resource specific review process.[28]

While it is true that generation assets based on a range of technologies have a physical life substantially longer than 20 years, there has been no demonstration that any asset type has a financial life longer than 20 years. The Market Monitor is open to unit specific demonstrations that the financial life of any asset is longer than 20 years but the authority to make such demonstrations should be limited to a reasonable financial life, e.g. 25 or at most 30 years. If asset life is going to be reconsidered, it should be reconsidered on a comprehensive basis, including the calculation of Gross and Net CONE in the Quadrennial Review for purposes of setting capacity market prices and including the default offers for all technology types. There has been no demonstration that investors in some asset types are subjectively more willing to take investment recovery risk than investors in other asset types. That would be inconsistent with rational capital markets.

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27 Proposed OATT Attachment DD § 5.14(h)(4)(B)(ii).

28 Proposed OATT Attachment DD § 5.14(h)(3)(B).

2. Resource Specific Calculations for Demand Resources and Energy Efficiency Resources

PJM proposes that resource specific calculations for generation backed Demand Resources "shall only consider the resource's costs related to participation in the Reliability Pricing Model and meeting a capacity commitment."[29]

PJM proposes that resource specific calculations for generation backed Demand Resources "shall only consider the resource's costs related to participation in the Reliability Pricing Model and meeting a capacity commitment."[30]

The full costs of the generating unit should be included as the cost of generation backed Demand Resources.

3. Resource Specific Calculations for Resources with No Must Offer Requirements

The Market Monitor recommends that resource specific minimum floor offer prices be calculated considering the amount of capacity offered in the auction. This is particularly important in the case of resources that are not subject to the Capacity Performance must offer requirement. If a capacity value such as the RPM accredited capacity value were used and a resource were to not offer its full accredited value in the auction, the resulting sell offer would be artificially low. Using an incorrect denominator in the calculation is contrary to the concept of the revenue requirement which is the basis for the MOPR calculation. Allowing seasonal resources to calculate a sell offer based on a full delivery year rather than the number of days it would be receiving capacity revenues results in a similar issue of artificially reducing the sell offer.

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[29] Proposed OATT Attachment DD § 5.14(h)(3)(B).

[30] Proposed OATT Attachment DD § 5.14(h)(3)(B).

4. Rules Regarding Market Monitoring Review Processes

PJM proposes to modify the resource specific review process by adding language constraining how the Market Monitor conducts its independent reviews.[31] PJM would include an "open and transparent" requirement on the Market Monitor's review for market power concerns and on PJM's administrative compliance review.[32] Changing PJM and the Market Monitor roles, and how PJM and the Market Monitor interact within those roles, exceeds the scope of the compliance directive. Such changes are not properly a part of this proceeding and should be rejected.

The Market Monitor conducts the monitoring function, in "an open and transparent manner" whenever it is appropriate and possible. PJM states (at 79) that the purpose of imposing an "open and transparent" requirement on the Market Monitor's unit specific review of offers is to ensure "PJM and the Market Monitor are kept apprised of each other's review." This rationale is not consistent with the independence of the market monitoring function and is otherwise nonsensical. Even if PJM's rationale were reasonable, the language proposed should be rejected because its scope exceeds its asserted purpose. In addition, tariff language concerning implementation of the market monitoring function is required to be consolidated in Attachment M and not scattered throughout the market rules.[33] Order No. 719 requires consolidation of the rules for market monitoring in the tariff for good reasons, including the protection of the Market Monitor's independent and

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31 Proposed OATT Attachment DD § 5.14(h)(3)(F).

32 *Id*.

33 *See Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 125 FERC ¶ 61,071 at P 312 (2008) ("Order No. 719") ("Given the critical nature of MMU duties, the Final Rule requires RTOs and ISOs to include in their tariffs ethical standards for their MMUs. The Final Rule also requires RTOs and ISOs to consolidate all of their MMU provisions into one section of their tariffs.").

efficient operation. The proposed tariff language at Section 5.14(h)(3)(F) interfering with market monitoring processes should be rejected.

G. Commercially Aggregated Resources

For commercially aggregated resources where one or more of the underlying resources is eligible for a State Subsidy, PJM proposes to use a minimum floor offer price equal to the "the time and MW-weighted average of the applicable MOPR Floor Offer Prices (zero if not applicable) of the aggregated resources in such Sell Offer."[34] This approach would undercut the expanded MOPR and provide a gaming opportunity for market participants to artificially lower the applicable minimum floor offer price for a subsidized resource. The Market Monitor recommends that the minimum floor offer price for commercially aggregated resources where one or more of the underlying resources is eligible for a State Subsidy be set to the higher of the applicable floors.

H. Process for Establishing a Capacity Resource with a State Subsidy

PJM proposes that capacity market sellers must provide notification of whether or not each resource is a capacity resource with a state subsidy to PJM no later than 120 days prior to the RPM Auction for Generation Capacity Resources and no later than 30 days prior to the RPM Auction for Demand Resources and Energy Efficiency Resources.[35] The Market Monitor recommends that the deadlines be consistent and that notifications for all resource types be provided by the 120 day deadline. The purpose of the deadlines is to allow sufficient time for the Commission to resolve any issues that are identified prior to an auction clearing. Thirty days are insufficient.

As these notifications are related to the application of market power mitigations rules, these notifications should be required to be provided to the Market Monitor.

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[34] Proposed OATT Attachment DD § 5.6.1(h).

[35] Proposed OATT Attachment DD § 5.14(h)(1)(C)(i).

I. The Independent Role of the Market Monitor in Cases of Fraud or Material Misrepresentations

PJM proposes language that would allow it to apply the MOPR to an offer where PJM has determined that the basis for an asserted exemption involves fraud or misrepresentation.[36] The purpose of this provision is to allow PJM to clear an RPM Auction based on PJM's determination of the facts. A participant disagreeing with PJM's determination could raise the issue with the Commission. Likewise, if the Market Monitor disagrees, it may also seek to raise the issue with the Commission.

For this reason, the proposed language should not unnecessarily characterize the Market Monitor's role. Even more importantly, the language should not mischaracterize the Market Monitor's role by describing it as "advice and input." Such language contributes nothing, and serves only to create confusion. The "advice and input" clause is improperly included in proposed Section 5.14(h)(9) of Attachment DD to the OATT, and also in proposed Section 1 (Definitions C–D (Jointly Owned Cross-Subsidized Capacity Resource)) and proposed Section 5.14(h)(3)(F) of Attachment DD to the OATT.

The Market Monitor is not a subordinate consultant advising PJM on how PJM should implement the tariff.[37] The Market Monitor is an independent monitor, including monitoring PJM's conduct in administering the market rules, and necessarily develops positions on how PJM should administer the market rules.[38] Although PJM makes its own decisions about how to implement the market rules and has no obligation to adopt the

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36 Proposed OATT Attachment DD § 5.14(h)(9).

37 The Commission has explained that to preserve the independence of the market monitoring function it seeks to avoid placing that function in a position subordinate to the RTO. Order No. 719 at PP 361, 371 & 373 ("The Commission regulates public utilities, and it is the public utilities that we hold accountable for tariff implementation. To the extent this function is performed by MMUs, the MMUs are assisting the RTOs and ISOs in the administration of their tariff, which places the MMUs in a subordinate position to the RTOs and ISOs.").

38 *See* OATT Attachment M § IV.

Market Monitor's position, it is a regulated entity performing regulated functions. The Market Monitor may determine that is necessary to attempt to vindicate its position at the Commission.[39]

Independence is the issue. Subordinate consultants that PJM may hire from time to time to advise it are not charged to carry out an official monitoring function and do not attempt to persuade the Commission to compel PJM to take their advice. Nothing prevents PJM from informally soliciting advice from the Market Monitor on how PJM should perform its functions, but it is important to protect an independent market monitoring function and to avoid confusion about PJM's and the Market Monitor's roles by ensuring that the tariff language properly characterizes the Market Monitor's role.

The Market Monitor does not understand PJM's insistence on including confusing and unnecessary language obliging PJM to obtain advice and input from the Market Monitor in the course of PJM's implementation of the market rules.

PJM should be directed to remove on compliance all instances of language mischaracterizing the Market Monitor's role as providing advice and input to PJM.

J. Demand Resource and Energy Efficiency Resource Exemptions

PJM proposes to allow Curtailment Service Providers (CSPs) to identify load management locations and registrations prior to the 2022/2023 BRA for the purpose of determining exempted capacity.[40] The current pre registration process does not require firm contracts between the CSP and end use customer. CSPs must have all end use customers under contract in order to effectively apply the expanded MOPR and should be required to

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39 *See Potomac Economics, Ltd. v. PJM Interconnection, L.L.C.*, 171 FERC ¶ 61,039 (April 17, 2020); *PJM Interconnection, L.L.C.*, 167 FERC ¶ 61,084 at PP 70–76 (April 29, 2019), *reh'g denied*, 168 FERC ¶ 61,141 (August 30, 2019); *see also PA Solar Park, LLC*, 164 FERC ¶ 61,118 at PP 13–14 (2018).

40 Proposed OATT Attachment DD § 5.14(h)(7)(A).

do so. If load management locations were not linked to a cleared demand resource offer prior to the December 19th Order, they should not qualify for the DR exemption.

K. RPM Auction Schedule

PJM proposes that "in the event that legislation directly applicable to new elections of the FRR alternative is enacted before June 1, 2020, and upon request of a state public utility commission acting in its official capacity, PJM would have the limited ability to extend the schedule for the affected BRA to no later than March 31, 2021, for completion of the BRA."[41] The Market Monitor recommends that the next two Base Residual Auctions be held as soon as possible to restore transparency and certainty to the PJM markets. There is no reason to delay.

II. CONCLUSION

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

Respectfully submitted,

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41 Transmittal letter at 86.

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Dated: May 15, 2020

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Eagleville, Pennsylvania,
this 15th day of May, 2020.

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