Resource Aggregation in the Capacity Performance Market Design: Commercial Perspectives

Presentation to Seasonal Capacity Resources Senior Task Force

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- Wholesale power marketing -- origination
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- Clients include merchant generation, merchant transmission, RTOs, retail load
- Active in CP discussion with PJM and clients

Summary

There is commercial interest in developing resource aggregations to minimize under-performance risk and maximize RPM auction revenue, but executed transactions have been rare. Reasons for hesitancy include:

Category	Challenges	Degree of Difficulty
Finding Aggregation Partner	**-- Same modeled LDA requirement** **-- Seasonal resource imbalance** **-- “Cold calling”**	3
General	**-- Trust issues** **-- New type of transaction** **-- Limited CP experience**	2
Commercial	**-- One Market Seller** **-- Allocation methodology** **-- Strategy collaboration** **-- Confidentiality** **-- Collateral**	1.5

Transactional Complexities

The deal structure is unique: two sellers, one of which has to be the Capacity Market Seller. The parties have to agree on:

- How to allocate obligations penalties and credits
- Collateral support within the aggregation
- Auction strategy
- How to handle confidential data (for example, customer-specific DR information)
- Audit rights for non-Market Seller

All of those issues theoretically can be managed in negotiations, but finding potential counter-parties has been difficult – in part because of the numbers . . .

Intermittent Resources Eligible for 2019/20 BRA

LDA/Zone	DR/EE*	Solar**	Wind**
ATSI	687	--	--
ATSI-Cleveland	344	--	--
BG&E	830	--	--
COMED	2,517	3	439
DPL-South	424	1	--
EMAAC	1,080	50	--
MAAC	819	1	118
PEPCO	656	--	--
PPL	872	6	27
PSEG	260	39	--
PS-North	227	8	--
RTO	4,752	118	419

*DR/EE Source Data – PJM 2019/20 Base Residual Auction Results; represents DR/EE that cleared as CP (~ 14%) and Base (~ 86%) in the 2019/20 auction

**Solar/Wind Source Data – PJM 2019/20 RPM Resource Model; represents summer ICAP ratings

__Notes__: PJM did not publish total or locational MW for hydro/pumped hydro/other storage, which make up a significant class of potentially seasonal resources ; ~ 40% of DR offered as Base/CP, with most cleared as Base

Interconnection Queue

LDA	Solar***	Wind***
ATSI	57	67
ATSI-Cleveland	--	--
BG&E	14	--
COMED	--	401
DPL-South	707	33
EMAAC	146	--
MAAC	--	32
PEPCO	--	--
PPL	6	47
PSEG	31	--
PS-North	--	--
RTO	2,625	1,161

***Includes all projects in PJM's Interconnection Queue with a status of "Active" or "UC." There may be some overlap with the table at left

Can resources in nested LDAs that are part of a larger LDA form an aggregation (e.g., BGE & PSEG, to form an aggregate that could offer as a MAAC LDA resource)?

Transactional Issues & Suggested Approaches

[Blanket suggested approach: hire us]

Issue: Aggregate offer strategy (amount & price-quantity segments if any) requires mutual agreement. One side may be more/less risk-averse than the other
Suggested approach: 1) Jointly define and analyze the expected value scenario; 2) Iterate with different offer quantities (0-Max Allowed MW); 3) Pick the quantity that produces the highest return in the context of the expected value scenario; 4) Use price-quantity segments to address any remaining differences over risk
Issue: How to address collateral support when one of the parties has to be the Capacity Market Seller
Suggested approach: Using the same inputs that were used for the offer quantity analysis, start with a max exposure amount as follows:

(RCP x Deficient Days x Offer MW) + (Offer MW x Expected PAHs x Penalty Rate)

Example Collateral Calculation

<u>Assume</u>:
Party A Offer MW = 21
Party B Offer MW = 14
Forecast RCP = $150/MWd
Expected PAHs = 10
Penalty Rate = $3,642/MWh
Deficient Days = 365

Party A Max Collateral Amount = ($150/MWd x 365 Days x 21 MW) + (21 MW x 10 PAHs x $3,642/MWh) = $1.9 million

Party B Max Collateral Amount = ($150/MWd x 365 Days x 14 MW) + (14 MW x 10 PAHs x $3,642/MWh) = $1.3 million

The exposure is asymmetric because whichever party is the Capacity Market Seller will be on the hook for the aggregate resource committed capacity. The other party's exposure could be limited to the RPM auction revenue

For example, assume Party A is the Market Seller. Party B would post $1.3 million while Party A would post $767k ($150/MWd x 365 Days x 14 MW)

Max CP Offer Calculation

PJM agreed to a formulaic approach to determine the maximum amount of UCAP that an intermittent resource could offer in an RPM Auction. Expected hourly production (generally, a P-50 curve) is evaluated during the following hours:

Summer	**Hours Ending 15:00-20:00 EPT, June 1 through August 31**
Winter	Hours Ending 06:00-09:00 EPT and Hours Ending 18:00-21:00 EPT, January 1 through February 28/29

P-50 Generation for Generic 50 MW (ac) Solar PV Resource

Calculation of Estimated CP Offer Using Peak-Hour Period Hours (OATT, Attachment DD, Section 10(b))

Hour	January	February	March	April	May	June	July	August	September	October	November	December
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.10	0.37	1.64	3.23	1.49	0.53	0.00	0.00	0.05	0.00
8	1.68	4.44	4.64	9.81	14.34	16.07	11.70	10.31	4.20	1.87	4.86	1.85
9	13.49	19.00	19.00	25.71	24.17	28.24	22.97	22.92	18.55	15.27	18.42	13.86
10	19.62	25.78	26.46	32.00	30.14	33.89	28.70	28.63	25.66	25.29	23.17	18.13
11	21.75	26.53	28.53	33.86	35.48	36.13	31.96	32.83	28.00	29.47	23.84	19.50
12	22.07	27.12	28.00	34.79	36.51	37.61	35.21	34.91	28.93	29.44	23.18	18.22
13	21.52	26.63	27.76	34.95	36.36	37.69	36.76	35.12	30.79	29.36	23.14	19.45
14	22.76	28.43	28.75	34.39	36.74	36.03	35.97	36.05	31.60	29.22	20.35	20.18
15	22.50	27.73	29.26	34.27	35.37	37.67	37.90	37.68	32.18	30.07	22.32	18.34
16	19.30	25.80	28.97	34.12	33.53	36.26	34.63	35.79	30.46	28.00	16.86	13.07
17	6.71	16.29	25.15	30.16	30.08	34.68	29.32	32.24	27.81	22.71	2.77	1.80
18	0.08	2.04	17.21	23.37	23.71	30.64	24.52	25.29	21.05	9.76	0.04	0.00
19	0.00	0.00	5.05	11.05	13.92	21.95	15.64	14.53	5.34	0.57	0.00	0.00
20	0.00	0.00	0.01	0.84	2.02	5.51	3.84	1.77	0.05	0.00	0.00	0.00
21	0.00	0.00	0.00	0.00	0.00	0.03	0.01	0.00	0.00	0.00	0.00	0.00
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MWh/Day	15.25	25.48				166.71	145.85	147.29				
Days/month	31	28				30	31	31				
MWh/Month	473	714				5001	4521	4566				
Hour/Day	8	8				6	6	6				
Hours/Month	248	224				180	186	186				
Weighted annual average (MW)		15										

Allocation of Penalties/Credits

Objective: determine equitable fixed ratios for distribution of performance-based cash flows

Risk analysis

Resource Aggregation: solar and wind

P-50 production curves associated with generic 100 MW installed wind resource and generic 50 MW solar resource (single-axis tracking and fixed-tilt) scaled up to 80 MW installed

18 Performance Assessment Hour scenarios modeled

Scenarios based on different combinations of actual Emergency Event Hours for the period 2005-15 for Rest of RTO

Scenarios differentiated by:
# of PAHs
Seasonal occurrence of PAHs
Hourly PAH distribution
Cleared capacity amount

Risk Analysis Input Assumptions

RPM clearing price: $150/MWd

Net CONE: $299.30/MWd → non-performance penalty (& over-performance credit) = $3,642/MWh

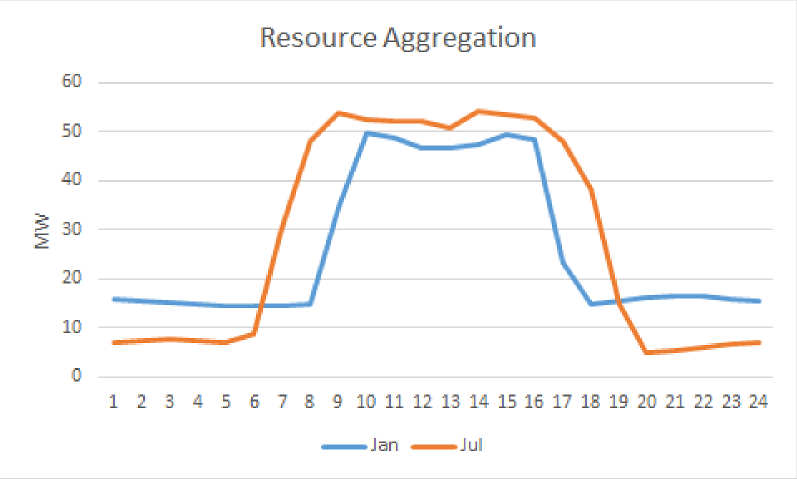
Cleared capacity amounts:

	Max Cleared Capacity (MW)	Average Cleared Capacity (MW)
Wind resource	**21**	**15 (average over expected summer PAHs)**
Solar resource	**14**	**4 (average over expected winter PAHs)**

Risk Analysis Settlements

<u>(Restating) Analysis objective</u>: determine equitable split of penalty/credit across <u>all</u> scenarios that results in settlements roughly equivalent to cleared capacity shares (wind, 60%; solar 40%). Assumes RPM auction revenue split proportionally in all scenarios

<u>Methodology</u>: solve for split, subject to sharing constraint, that accurately reflects each resource's contribution to over- and under-performance



<u>Result</u>: approximate equivalence achieved if:

Wind receives 75% of penalty/credit for <u>winter-only</u> PAHs
Solar receives 75% of penalty-credit for <u>summer-only</u> PAHs

"Summer" can include May based on PAH history

‘PJM-Assisted’ Resource Aggregation

PJM combines summer-only resource offers with winter-only resource offers to create synthetic aggregated CP resource (if combined offer price is lower than “real” CP resource offer price)

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This approach would eliminate the General and Commercial concerns, but it would raise additional challenges: for example, what is the clearing price for each seasonal resource? What is a summer resource’s non-summer obligation?