US Electric Utilities & IPPs

What did the Street Miss on the PJM Auction?

Equities

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We and Street under-estimated the shift towards more aggressive bidding

We attribute much of the 'recovery' in prices in the latest PJM capacity auction for 2017/18 to $120/MW-day (up from $59/MW-day last year) to a significant shift in bidding strategy, with ~9.7 GW of capacity opting not to clear. With no significant new EPA rules, we attribute much of the decline in generation to more aggressive bidding strategies, likely with EXC and NRG (the two largest generators in PJM) opting to bid in their portfolio at higher prices, given lower historic energy prices; bidding in these full costs (ACRs in PJM lingo) was discussed explicitly by EXC as part of its efforts to more rationally bid its nuclear portfolio. Meanwhile, we suspect NRG has opted not to clear much of the EME Midwest Gen portfolio due to IL MPS standards, set to ratchet up for the portfolio in 2017 to yet a crucially tighter SO_2 requirement. We also believe FE opted not to clear ~half of its capacity in the ATSI zone, continuing this theme.

But who wins? Mostly EXC, NRG, FE, and DYN, but whole sector should benefit

Despite the lower MWs committed through the use of portfolio bidding, all four companies are among the biggest beneficiaries of the auction results. We suspect the entire sector will continue to benefit from the trade, however, more Eastern-oriented MAAC names could still be more muted in upside given the substantial announcement of new and converted gas-fired capacity.

What does this mean? Need to handicap how much capacity cleared

We believe an important lesson learned from the auction will be the handicap applied to the capacity cleared in the auction, with companies increasingly needing to disclose how much capacity they have cleared; many investors have historically largely assumed the bulk of any IPPs portfolio was sold into the auction. We suspect a meaningful reduction to both NRG's and EXC's portfolio could impede the Day 1 'upside' from the strong $120/MW-day clearing price. Specifically, we flag EXC did not clear ~4GW of its nuclear portfolio (incl. Quad Cities, Byron, and Oyster Creek). We attribute the bulk of the uncleared capacity to the two largest market participants who have clear incentives to keep pricing higher). Meanwhile, we suspect others (PPL, DUK, AEP, AES) continued to clear the bulk of their capacity in anticipation of a sales processes.

Consolidation should only further drive portfolio bidding strategies in PJM

We believe the current trend of leveraging portfolio bidding strategies to drive upside in auction results is likely to only continue in future auctions, as the sector is poised to see substantial consolidation in the PJM footprint in the coming year. We see these added 'synergies' as further bolstering the argument for consolidation in the near term – and outside of any contemplated math disclosed by companies. Specifically, we see sale (consolidation) of Ohio's merchant portfolio to a single entity as enabling further upward pressure on the RTO region; we continue to see DYN as the most likely consolidator.

Top of the Power Cycle in PJM Taking Shape

2014 and 2015 appear to be the top of the power cycle

The latest auction provides comfort PJM pricing is still intact – for now

Mismatch of timing of coal retirements and new gas gen creates boom-bust in PJM

Following the latest auction results, we believe the latest rally in power equities could yet continue through the balance of the year. While we continue to see upside to forwards as liquidity is brought to bear on 2015 forwards for summer, we worry about what the outlook will be as investors peer beyond 2015 given the continued wave of new gas plants suggests we may well be approaching the 'top' of the power cycle across the PJM market in the coming 18 months. We suspect this summer and next summer will prove crucial for generators seeking to extract rents on the back of coal generation retirements prior to new gas entrants capturing market share. As such, we think we're not quite at the top of the Power cycle– rather – this appears to be a 2015 event. The thesis for power beyond this period remains predicated on the ability for incremental natural gas usage to have a positive feedback effect on overall gas prices—as we believe new gas fired generation will largely drive a backwardated view of heat rates in PJM. The latest auction only reiterates our view that a mini-boom in gas construction/conversions will continue, with still meaningful capacity in the wings to clear in future years.

What's next after the auction? Focus on M&A and EPS revisions.

Positive EPS revisions are relevant for names like DYN, EXC, NRG, and PPL among others

M&A will primarily benefit DYN, but also PPL

Seeing the auction as a 'relief' for many investors, we suspect EPS revisions will continue to provide a positive tailwind to power equities, albeit slowing a bit given weakness in power in recent days. We suspect the trade towards M&A will once again take the lead. We reiterate Dynegy as favorite power levered name – not just on its meaningful (and typically under-stated exposure) to the auction, but also the lever to the continued consolidation thesis. With the auction in the rear view mirror, we would expect initial short lists to be released via media outlets in the weeks ahead on portfolios for sale—specifically AES (DPL) as well as Duke. The fate of AEP's assets appear tied to success in implementing a PPA rider through its ESP filing. Finally, we suspect investors could yet see relief in investing in PPL for a spin/sale of its own Supply business; we believe any transaction (spin) without meaningful synergies could be a bit disappointing to Street expectations though.

Where are we more comfortable for the time being?

Gas constraints in the Northeast appear poised to remain for longer

In the near term, we reiterate our belief that [gas] constraints will remain the theme du jour in power, as tremendous gas price basis is likely to persist for quite some time in the New York and New England markets. We sense delays in gas pipeline construction as enabling further winter price spikes for Winter 2015 and 2016. This continued volatility complements our more constructive view on power through the medium term. We suspect bottlenecks, particularly into New England could yet last late into the decade depending on the success of NESCOE's efforts in procuring new gas pipe on socialized basis.

What about the economics of power? Upside is heading Westwards.

As Appalachia's 'end game' appears closer – longer-term focus will shift towards Western PRB retirements

Every dog has their day. We believe the 'next' power trade that could yet emerge late in the decade revolves around a further iteration of coal regs focused on retrofitting or retiring the last big untouched coal portfolios – The PRB plants. We suspect Regional Haze requirements coupled with price SCR retrofits could yet drive the 'next' trade in to the ~2020 timeframe. Moreover, Illinois state regs at this point in time will drive further DYN and NRG PRB units out of the market, tightening in 2018-2020E. While a bit too long term for many, this emerging thesis focus bears yet further scrutiny under any focus on carbon reductions.

What to make of the coming Court decision on DR: the next big quagmire.

The courts pursued the "nuclear" option for Demand Response industry on Friday

This is a potential major change to power markets- upside?

Following the Court of Appeal's last minute decision on Friday to relegate demand response as a 'retail' product – and outside of the jurisdiction of FERC – at least for the purposes of energy markets, we flag FE has filed with FERC for an emergency order rejecting the outcome of the PJM capacity auction results from Friday on the grounds that Demand Response can no longer participate in the RPM market. While we see low likelihood to a revision of the latest results given the uncertainty involved, we do see credibility that there could yet be fundamental reform on how Demand Response is integrated into the markets (initially energy, but could very well entail capacity reform as well).

Sensitivity Tables & Views from PJM Auction

We include a brief assessment of the PJM auction, by impacted equity. We flag that **NRG**, **Exelon**, **FirstEnergy** and **Dynegy** appear to be the most positively impacted by the results. While all power names are largely positively benefitted, we see PPL as among the least given the likely continued expansion of new gas plants in/near its service territory of gas plants. Meanwhile, we temper our view of PSEG to reflect this concern of continued gas plant expansions as well.

Figure 1: Auction Impacts by Equity – Our View on the Auction

	Positive /Negative /Neutral?	RTO (MWs)	PS (MWs)	Total	$ Mn	Shares O/S	Impact to EPS vs. "Street" Expectations	% of Total (EBITDA or EPS)
IPPs								
AES (via DPL)	Mild Postive	3,818		3,818	56	725	0.05	**3.3%**
DYN (includes IPH Imports)	**Very Positive**	2,700		2,700	39	100		**7.5%**
CPN	Mild Postive	4,424		4,424	65	423		**3.3%**
NRG (Classic, GenOn, EME) w/ ~3GW haircut	**Very Positive**	12,136		12,136	177	337		**6.2%**
Competitive Integrated								
EXC (w/o ~4GW Nukes Not Clearing)	**Very Positive**	20,914		20,914	305	859	0.23	**8.3%**
FE (W/o ~3.5GW of coal in ATSI)	**Very Positive**	10,568		10,568	154	420	0.24	**8.2%**
PEG	Positive	3,933	4,667	8,600	143	506	0.18	**6.3%**
PPL	Mild Postive	9,951		9,951	145	632	0.15	**5.9%**
More Regulated								
AEP	Positive	8,668		8,668	127	488	0.17	**4.4%**
DUK	Mild Postive	6479		6,479	95	707	0.09	**1.7%**
Total Owned by Generators in PJM				**88,258**	**Average**			**5.5%**

Source: PJM, FactSet, and UBS estimates; approximate capacity.

We caution the above exercise is a simple screen using the baseline expectation for RTO to clear at $80/MW-day, vs. the actual result of ~$120/MW-day, a $40/MW-day positive relative to Street consensus into the event (per our previous survey results). We did not parse out MAAC prices separately, but note that the survey auction results here expected ~$95/MW-day muting the uplift, particularly with the bulk of the new capacity continuing to be located in this region (hence our muted view on PPL relative to others).

Figure 2: Price Expectations for Auction vs. Actual ($/MW-day)

	Price- 2016/2017	Expectations- Survey Results	Actual Price for 2017/18	Delta
PS	$ 219	$ 165	$ 215	**$ 50**
MAAC	$ 119	$ 95	$ 120	**$ 25**
RTO	$ 59	$ 80	$ 120	**$ 40**

Source: PJM, UBS Survey and UBS estimates

Cleared Prices from the Auction:

We include cleared prices from the auction below, with just the PSEG (and PS-North) region of PJM clearing separately relative to previous auction datapoints. While we suspect capacity prices remain structurally under pressure in future years (seeing only an acceleration of late in interest for new gas builds), we see continued reform efforts and the potential for massive demand response overhaul to drive another positive data point next year.

Figure 3: Summary of PJM Capacity Auction Results

	2013/14	2014/15	2015/16	2016/17	2017/2018	UBSe 2017/18	Survey 2017/18
Resource Clearing Prices ($/MW-day)							
RTO	$27.73	$125.99	$136.00	$59.37	$120.00	$70.00	$75.00
EMAAC	$245.00	$136.50	$167.46	$119.13	$120.00	$70.00	$90.00
SWMAAC	$226.15	$136.50	$167.46	$119.13	$120.00	$70.00	$90.00
MAAC	$226.15	$136.50	$167.46	$119.13	$120.00	$70.00	$90.00
DPL-S	$245.00	$136.50	$167.46	$119.13	$120.00	$70.00	$90.00
PS-N	$245.00	$225.00	$167.46	$219.00	$215.00	$200.00	$165.00
PSEG	$245.00	$136.50	$167.46	$219.00	$215.00	$200.00	$165.00
PEPCO	$247.14	$136.50	$167.46	$119.13	$120.00	$70.00	$90.00
ATSI			$357.00	$114.23	$120.00	$70.00	$83.00
Reserve Margin	20.2%	19.6%	20.2%	21.1%	19.7%		

Source: PJM and UBS estimates/survey results

Aggressive bidding strategies drive up RPM auction results

What was the secret sauce to the latest auction? Nuclear and coal plants exercising their ability to bid in 'higher' prices to keep prices high. This is effectively a one-time lever large incumbents could use to drive prices higher, leveraging the fact that their bidding flexibility under PJM's tariff is dictated by 3-year historic energy revenues (2011-2013), which are quite depressed, enabling incumbent generators to recover substantially higher prices from the capacity auction.

Figure 4: Actual vs UBSe BRA Model Delta's - How to Reconcile to the higher auction results?

	Actual (MW)	UBSe (MW)	Diff (MW)	Impact ($/MW-day)
UBSe RTO Assumption				**$ 72.87**
Deltas				
New Gen	5,387	2,573	2,814	$ (20.99)
Gen Reduction/Bidding Strategies	(9,760)	(4,032)	(5,728)	$ 42.73
Uprates	474	143	331	$ (2.47)
Reactivations	991	-	991	$ (7.39)
DR Limited	(7,527)	(6,387)	(1,140)	$ 8.50
DR Ex Sum	4,693	5,361	(668)	$ 4.98
DR Annual	1,401	(89)	1,489	$ (11.11)
Imports	(2,957)	(500)	(2,457)	$ 18.33
EE	222	195	27	$ (0.20)
UBSe RTO outcome per model with corrected inputs	**(7,078)**	**(2,736)**	**(4,342)**	**$ 105.26**
Steeper supply curve				$ 14.74
Actual Result				**$ 120.00**

Source: PJM RPM results, UBS estimates

Modelling out the portfolio bidding upside: How to reconcile our estimates on the auction vs. actual results

Our supply/demand model of RPM auction results uses a supply curve based on outcome sensitivities for various bidding scenarios provided by PJM for the prior-year's auction. As a result of interaction with the administratively-set demand curve (provided through the release of updated parameters on May 7), <u>the price outcome was sensitive by ~$7.50/MW-day per 1 GW change in supply.</u> The 4.3 GW difference in actual results from our assumptions therefore accounts for ~$32 of the higher actual result (we would have been at $105.26 instead of $72.87). The remaining $14.74 difference is the result of a steeper supply curve present in this year's auction compared to last year's, which is not altogether too surprising given that the greatest impact on higher results was 5.7 GW of aggressive bidding behaviour that likely knocked out (withheld) marginal baseload coal at the bottom of the stack. Also, as illustrated in the table above, the other most significant impact on the auction was the surprisingly severe 2.4 GW reduction in imports that pushed the price up at least $18.33. Otherwise, our assumptions for demand response (DR), energy efficiency, new generation, and uprates were all reasonably close.

Withholding strategy math works up to a point

Exelon's new bidding strategy appears entirely consistent with PJM rules – and reflects continued challenges to its nuclear portfolio

In the table below, we calculate the net revenue uplift from hypothetical withholding scenarios for EXC (we do not intend to imply that this behavior took place as described). As illustrated, maximum benefit can be obtained by withholding just enough supply to drive prices received for the remaining fleet up without eliminating too much revenue and reducing the overall benefit. <u>In the first column, the maximum uplift is obtained by withholding 4,457 MW of a 25,000 MW fleet (roughly consistent with the 4.225 GW of capacity disclosed as being withheld – Quad Cities, Byron, and Oyster Creek).</u>

It's important to note that the outcome is highly dependent on the initial assumption for where the auction would have come out at without any withholding. Lower baseline assumptions generally incentivize more withholding since less revenue is removed by the withheld assets (less risk in the strategy) while overall net uplift increases as well. In our example, we use $60/MW-day as this baseline assumption. Withholding 4,457 MW thus results in a reduction of $267M of revenue but the incrementally $33.25 higher cross on the supply curve results in $1.9B of revenue for the remaining 20,543 MW fleet that's bid into the auction for a net uplift of $148M. The second column shows how increasing the withheld MWs beyond 4,457 MW results in a reduction of net benefit as incremental price improvement diminishes in relation to lost revenue.

At 8,914 MW withheld (36% of the fleet), there is no net benefit at all (breakeven). Given that only a relatively small portion of the fleet is required to be withheld for maximum benefit, we would conclude that EXC, at any rate, has more than adequate market power to drive auction results through an aggressive bidding strategy. Given that the actual RPM results included over 9 GW of reduced generation as a result of bidding strategies, we would have to conclude that more than one major auction participant used these strategies simultaneously, likely resulting an even greater pricing and benefit for the remaining bid fleets than anticipated. While outright strategic collusion is prohibited, participants may have been "telegraphing" their intentions to each other more subtly in public

comments from more than one company regarding potential retirements, seeking higher Avoided Cost Rates (ACR), etc, hence PPL's comments that the auction outcome was driven by Bidding Strategies this year.

Lastly, adding to future market power leverage, we continue to await FE's petition before FERC on permissible ACR calculation changes that would enable yet higher prices on many assets (particularly nuclear assets).

Figure 5: Calculation of Uplift from Hypothetical Withholding Scenarios ($M) for EXC

			EXC max uplift		EXC b/e
Fleet RTO MWs	(a)		25,000		25,000
Baseline RPM Price Assumption ($/MW-day)	(c)	$	60.00	$	60.00
Baseline Fleet Revenue Assumption ($M)	(e)	$	1,500	$	1,500
MWs Withheld	(b)		(4,457)		(8,914)
Baseline RPM Price Assumption ($/MW-day)	(c)	$	60.00	$	60.00
Reduction to Baseline Revenue Assumption ($M)	(f)	$	(267)	$	(535)
Incremental RPM Price Impact ($/MW-day)	(d)	$	33.25	$	66.50
Net Fleet Bid (MWs)	(a) - (b)		20,543		16,086
New RPM Price Assumption ($/MW-day)	(c) + (d)	$	93.25	$	126.50
New Net Revenue Outcome ($M)	(g)	$	1,916	$	2,035
Withholding Uplift $M	(g) - (f) + (e)	**$**	**148**	**$**	**0**

Source: UBS estimates

Other Auction Drivers to Consider:

New Gas Generation Additions are Meaningful as well

We include a summary of the new supply additions by type below, indicating that the latest auction saw the highest amount of new capacity additions (as well as specifically CCGTs) of any prior period, including last year's auction. We attribute the steam uptick primarily to coal-to-gas conversions, using existing boilers.

Figure 6: Latest Capacity Auction - New Resource Additions (Includes New Units, Uprates, and Reactivations)

Total New Resources	2013/14	2014/15	2016/2017	2017/2018	Cumulative	Fuel mix
Single-Cyle Turbine	385	213	608	203	4,245	16%
CCGT	764	650	4,380	5,210	13,434	50%
Diesel	6	45	42	130	437	2%
Hydro	-	174	7	112	690	3%
Steam (coal)	240	139	1,564	1,158	5,721	21%
Nuclear uprates	47	107	103	11	1,174	4%
Solar	10	35	34	27	107	0%
Wind	285	220	69	2	1,017	4%
Total	1,738	1,583	6,806	6,854	26,824	100%

Source: PJM and UBS Estimates

The key question remains how much of this capacity will ultimately get built. We look for this question to get resolved in coming months as many of these generators come to market to seek both equity and debt financing (few likely have financing already in place).

It remains unclear how much of the capacity cleared in prior auctions has actually begun development – and to what extent any of this capacity was ultimately 'pulled out' of the market in the latest reversal of new generation (a potential); we look to an upcoming fuel report from PJM on the breakdown of cleared capacity to provide some initial clues.

We flag that much of this capacity is actually in the EMAAC and MAAC portion of PJM. We suspect energy prices could be disproportionately impacted in the eastern footprint of PJM, pressuring 2017 and 2018 forward power prices.

Figure 7: How much new generation cleared the auction? A Lot, in all markets.

This Year	Cleared 2017/18			Offered 2017/18			Uncleared
Region	Uprate	New	Total	Uprate	New	Total	Total
EMAAC	65	1,746	1,812	65	1,746	1,812	-
MAAC-only (excl EMAAC)	94	2,672	2,765	94	2,753	2,847	81
RTO-only (excl MAAC)	181	1,510	1,690	1,022	1,629	2,651	961
Total PJM Footprint	**340**	**5,927**	**6,267**	**1,181**	**6,128**	**7,309**	**1,042**
Last Year..	**Cleared 2016/17**			**Offered 2016/17**			**Uncleared**
Region	**Uprate**	**New**	**Total**	**Uprate**	**New**	**Total**	**Total**
EMAAC	383	59	442	579	216	794	352
MAAC-only (excl EMAAC)	279	1,496	1,775	279	1,496	1,775	-
RTO-only (excl MAAC)	519	2,727	3,246	545	3,484	4,029	783
Total PJM Footprint	**1,181**	**4,282**	**5,463**	**1,403**	**5,195**	**6,598**	**1,135**

Source: PJM and UBS Estimates

It remains unclear precisely which units committed into the auction?

We include a list of known plants to us that are exploring new plants in the PJM footprint. We anticipate we could yet have missed some, particularly given the total quantity of capacity that sought MOPR exemptions for the latest round of additions (total of 11.4GW of new capacity granted, vs. 14GW requested for the latest auction). This 11.4GW is on top of the 7.8GW that didn't clear last year. Netting out the 6.3GW that cleared this year, we still see 12.9GW that has received MOPR approvals, but not yet cleared in the auction for a variety of issues. For example, we understand Panda's latest project in Maryland ran into permitting issues (Mattawoman), suggesting it did not clear – and could yet in future auctions

Figure 8: More New Generation Still Lingers too?

MOPR Exemptions	Requested	Granted
2016/17	13,253	13,253
2017/18	14,030	11,394
Total Cleared in '16/'17		(5,463)
Total Cleared in '17/'18		(6,267)
Remaining Approved New Gen but not cleared		12,917

Source: PJM and UBS estimates

Figure 9: Summary of Potential New Generation Resources bid into auction

Project	Region	Fuel	MW	Announced	Est Cost	Projected Completion
MAAC						
Wildcat Point / ODEC	MD (PJM)	Natural Gas	1,000	April '13	$1,100Mn	2017
Mattaw oman / Panda	MD (PJM)	Natural Gas	829	August '13	$945Mn	July 2017
Keys Energy Center	MD (PJM)	Natural Gas	735		$750Mn	June 2016
Woodbridge	NJ (PJM)	Natural Gas	700	2011	$845Mn	January 2016
Good Spring	PA (PJM)	Natural Gas	330	December '12	$730Mn	2016
Berks Hollow	PA (PJM)	Natural Gas	855		$750Mn	June 2016
Garrison II	DE (PJM)	Natural Gas	309	February '12	$340Mn	TBD
Lebanon Valley	PA (PJM)	Natural Gas	900		$1,045Mn	2017
Lackaw anna	PA (PJM)	Natural Gas		August '13	$500Mn	TBD
RTO						
Oregon Clean Energy	OH (PJM)	Natural Gas	799	September '12	$860Mn	May 2016
Stonew all	VA (PJM)	Natural Gas	750	September '12	$600Mn	March 2017
Carroll County	OH (PJM)	Natural Gas	700	July '13	$800Mn	2017
St. Joseph's Energy Center	IN (PJM)	Natural Gas	673	2011	$740Mn	Sept 2016
Nelson	IL (PJM)	Natural Gas	584	December '13	$630Mn	Jan 2015
Deerfield	MI (PJM)	Natural Gas	400			
Westmoreland	PA (PJM)	Natural Gas	900		$1,023Mn	2016
Rolling Hills Uprate	OH (PJM)	Natural Gas	564		N/A	2016
Total Potential MAAC			**6,768**			
Total Potential RTO-Only (Excl. MAAC)			**5,370**			
Total Cleared MAAC 2017/18			**4,577**			
Total Cleared RTO 2017/18			**1,350**			

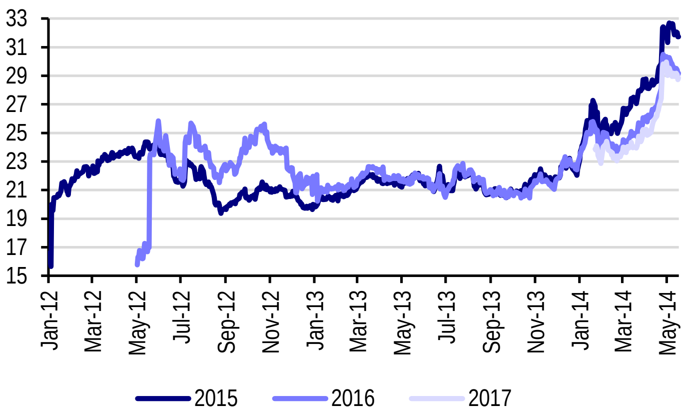
Source: PJM, Company Filings, and UBS estimates

But why did all this new capacity show up? Much higher spark spreads.

We flag that spark spreads, when using the Dominion-South delivery point versus PJM West have continued their upward trajectory suggesting new entrant economics are even better this year than last.

The big question for new entrants remains how willing they are to believe that gas will remain cheap (both nominally and on a relative basis versus Henry) by the time the plant is delivered (although initial ~5 year hedges on sparks enable financing today). That said, even hedges are not necessarily perfect in hedging exact gas price risk in a market with rapidly evolving gas price basis. We flag hedge effectiveness as a major recent issue for Northeast developers.

Figure 10: Robust Sparks have improved ~30% YoY due to cheap gas: PJM West-Dominion South Spark Spread on new 6.5 Heat Rate plant ($/MWh)



Source: Platts and UBS estimates

… And what to make of Demand Response Declining?

We flag that Demand Response also continued a modest slide too, with -1.2GW less clearing YoY, despite a total of -2.9GW less offered YoY. We attribute the recent declines in participation to continued efforts to increase the quality of demand response participating in the auction, further limiting the amount of Summer Extended and Limited products.

Could lower participation also signal some concern about future regs?

We attribute some further scaling back to the broader uncertainty of where further PJM reforms will go – and to what extent they could impact the incremental auctions for the 2017/18 delivery year.

<u>What are notable datapoints in the DR zones?</u>

1) We believe the upside from the PS zone can be attributed to a meaningful decline in PSEG zone DR participation, with -237MW cleared YoY.

2) Decline in PPL zone of -307 MW cleared likely reflects an abundance of DR in this region relative to PJM's decision to model out this region separately. As is illustrated in the final pricing, DR did not sufficiently exit the market in this zone to limit price compression

Figure 11: Demand Response and Energy Efficiency Changes YoY

		Offered MW			2017/18 Cleared MW			Delta vs. Last Auction		
Region	**LDA**	**Demand Response**	**Energy Efficiency**	**Total**	**Demand Response**	**Energy Efficiency**	**Total**	**Offered Δ vs. '16/17**	**Cleared Δ vs. '16/17**	**Uncleared**
EMAAC	AECO	134.8	0.8	135.6	134.7	0.8	135.5	(56.2)	(38.5)	0.1
	DPL	372.9	29.0	401.9	369.7	29.0	398.7	(91.9)	(62.0)	3.2
	JCPL	169.8	7.1	176.9	159.4	7.1	166.5	(85.3)	(61.1)	10.4
	PECO	494.1	24.8	518.9	480.0	24.8	504.8	(88.6)	(37.8)	14.1
	PSEG	392.7	18.7	411.4	388.4	17.6	406.0	(240.0)	(236.6)	5.4
	RECO	3.4	-	3.4	3.4	-	3.4	(9.0)	(6.7)	-
	Sub-Total	**1,567.7**	**80.4**	**1,648.1**	**1,535.6**	**79.3**	**1,614.9**	(571.0)	(442.7)	33.2
								-	-	
PEPCO	PEPCO	619.8	104.2	724.0	608.4	104.2	712.6	(43.5)	(34.8)	11.4
								-	-	
MAAC	BGE	803.2	123.7	926.9	791.2	123.7	914.9	(168.0)	(146.6)	12.0
	METED	306.6	12.8	319.4	298.9	12.8	311.7	(99.3)	(12.3)	7.7
	PENELEC	367.7	12.9	380.6	356.8	12.9	369.7	(82.0)	(71.7)	10.9
	PPL	812.7	35.6	848.3	686.2	35.6	721.8	(223.3)	(306.6)	126.5
	Sub-Total	2,290.2	185.0	2,475.2	2,133.1	185.0	2,318.1	(572.6)	(537.2)	157.1
SWMAAC		1,423.0	227.9	1,650.9	1399.6	227.9	1,627.5	(211.5)	(181.4)	23.4
Grand Total MAAC		**4,477.7**	**369.6**	**4,847.3**	**4,277.1**	**368.5**	**4,645.6**	**(1,187.1)**	**(1,014.7)**	**201.7**
RTO	AEP	1,445.5	136.3	1,581.8	1,426.1	136.3	1,562.4	(257.7)	66.5	19.4
	APS	940.8	10.3	951.1	928.9	10.3	939.2	(13.2)	240.2	11.9
	ATSI	1,064.4	142.0	1,206.4	1,020.2	142.0	1,162.2	(913.2)	(846.3)	44.2
	COMED	1,499.6	583.3	2,082.9	1,478.1	583.3	2,061.4	(66.1)	398.5	21.5
	DAY	211.9	49.2	261.1	209.4	49.2	258.6	(53.3)	(1.1)	2.5
	DEOK	194.0	17.5	211.5	192.4	17.5	209.9	(189.1)	(99.7)	1.6
	DOM	1,157.8	20.7	1,178.5	1,141.1	20.7	1,161.8	(309.2)	12.8	16.7
	DUQ	161.9	10.6	172.5	161.4	10.6	172.0	(45.2)	24.6	0.5
	EKPC	140.1	0.5	140.6	140.1	0.5	140.6	3.8	140.6	-
	Sub-Total	6,816.0	970.4	7,786.4	6,697.7	970.4	7,668.1	(1,843.2)	(197.0)	118.3
Grand Total		**11,293.7**	**1,340.0**	**12,633.7**	**10,974.8**	**1,338.9**	**12,173.1**	**(2,893.5)**	**(1,219.2)**	**460.6**

Source: PJM and UBS Estimates

… And what about prices by Product? Not materially lower.

We flag the latest restrictions on Summer Extended and Limited did not substantially impact the auction results as the only region to see substantial price separation (downwards) for these products was the PPL region. We expect DR providers to continue to focus on expanding Summer Extended Products in future auctions to the extent to which this remains a lower-cost DR product that can be supplied to the market at (or near) that of the overall clearing price.

Figure 12: RPM Results, broken out by DR production and by region

DR Prices	2017/18
RTO	
Annual	$120.00
Summer Extended	$120.00
Limited	$106.02
PSEG	
Annual	$215.00
Summer Extended	$215.00
Limited	$201.02
PPL	
Annual	$120.00
Summer Extended	$53.98
Limited	$40.00

Source: Company reports and UBS estimates

And then Transmission Imports Declined too…

Total cleared transmission imports were below those allowable at 4.5GW, even under the more restrictive regional cap of ~5.4 GW (and even lower than the RTO-wide formal cap is 6.5GW). We attribute the decline in cleared transmission to a combination of factors –including:

1) Transmission import caps, which effectively put substantial downward pressure on non-exempted capacity from participating in the auction;

2) Less capacity applying for the exemption, suggesting that generators did want to commit their capacity for protracted periods required under the exemption process. This would suggest a long-term mildly more bullish view for MISO and the Southeast. Our read remains that merchant generators and regulated utilities selling off-system capacity into the market did not want to commit for the long-term for fears that they could have a monetization opportunity if they were an IPP (back to a regulated utility), or for a regulated utility, concerns over whether regulators would demand this capacity back to serve native load.

We had thought the bulk of the 7.5GW of transmission imports would seek exemptions; this was clearly not the case.

3) Even those transmission imports that had secured exemptions, opted not to clear all of their capacity (we estimate 612 MW). This is primarily due to zero import prices exhibited in certain regions, as they were 'constrained' (see tables below for pricing). Further, with NRG likely bidding under a 'portfolio' approach given its size – and interest in saving the GenOn subsidiary – we believe it may have yet scaled back its capacity commitments.

It's notable that the two regions entirely saturated by Exempted capacity imports both cleared at $0/MW-day, effectively committing the capacity for free [odd in our view]. Dynegy exports to PJM via West region 2, which cleared at the full price.

Figure 13: Digging into the Transmission Imports Math

PJM Transmission Imports Math		Disclosed Prelim Regional Limits	Cleared Capacity by Zone	Prices by Zone ($/MW-day)
Exempted Transmission Imports	4,777			
Exempted Transmission Imports - Cleared per PJM	~4,000			
Remaining Imports by Region				
North (NYISO and ISO-NE)	27	1,598	223	120
West 1 (MI and Northern MISO)	-	2,301	1,268	-
West 2 (Southern IL / MISO)	397	767	2,624	120
South 1 (TVA, etc)	188	1,278	235	120
South 2 (Carolinas)	-	2,493	176	-
Remaining under Zonal Caps	612.0	8,437	4,526	
Total Exempted + Under Remaining Cap	5,389			
Actually Cleared in 2017/18	4,526			
Last Year Cleared	7,500			
YoY Decline	*2,974*			

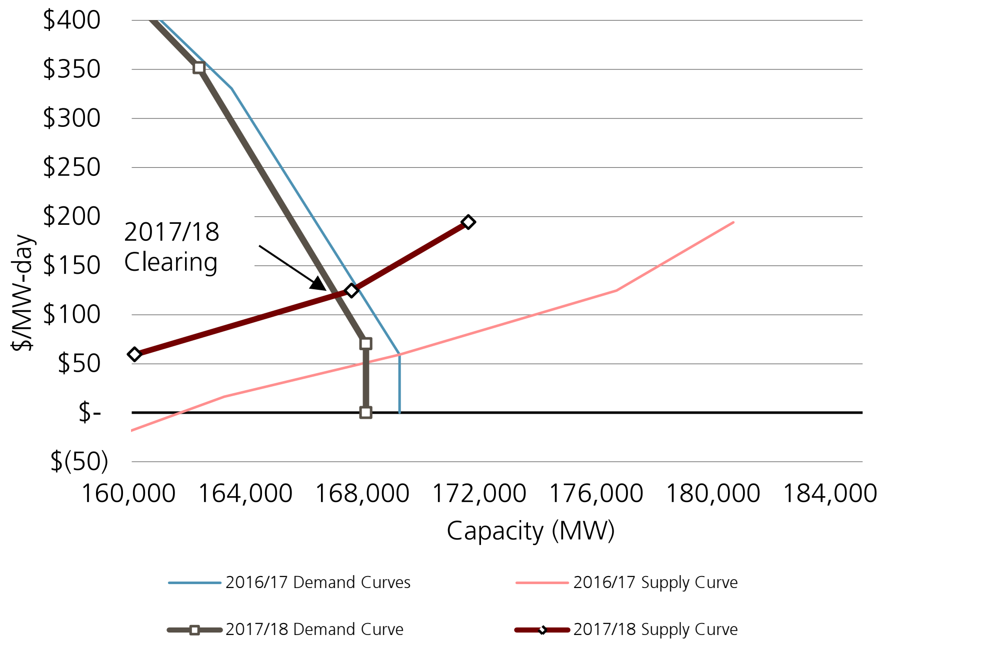
Major Drop YoY

Source: Company reports and UBS estimates

So what to the Supply and Demand Curves Look Like?

We include our final curves for 2017/18, with our best estimate of the supply curve. We flag the curve appears to have steepened for RTO versus the parameters released previously for the region as MAAC and ATSI were consolidated.

Figure 14: Supply and Demand Curves for latest 2017/18 PJM capacity auction



Source: PJM and UBS estimates

What about the math on the rest of the world?

We include our final YoY adjustments to derive the price in the RTO region. We flag our final -1.975GW plug 'resolves' the shift in the curve shape, given RTO's combination with MAAC and ATSI regions in the latest auction.

Figure 15: Supply Shifts YoY for 2017/18

RTO Supply Assumptions (MW)	
Retirements	-9,760
Dynegy/PSEG Uprates	+474
Supply Curve Adjustment	-1,975
New Generation/CC Conversions	+6,378
DR MW (Annual)	+1,401
DR Strategy Offset+Price Uplift	+0
DR MW (Extended Summer)	+4,693
DR MW (Limited)	-7,527
Net DR Shift	**-1,433**
Imports	-2,957
Energy efficiency	+222
Total	-9,053
Outcome 2017/18 UBSe	$120.00
Outcome 2016/17	$59.37

Source: PJM and UBS estimates

What about the Companies? Specific Estimate Revisions.

AEP:

The revenue uplift for AEP is ~$10Mn as the blended 2017 RTO price assumption increased ~$3/MW-Day, driving ~$0.01/sh EPS improvement. We believe AEP may very well have opted not to clear its Conesville plant in an effort to increase the credibility of the plant seeking a contract in Ohio (despite the latest setback in its ESP given negative staff reaction to PPA rider).

Figure 16: AEP Earnings Estimate Summary

EPS Contribution	2012A	2013A	2014E	2015E	2016E	2017E
Distribution Utilities	2.51	2.28	2.62	2.67	2.90	2.83
Genco	0.62	0.68	0.51	0.45	0.28	0.30
Transmission Projects	0.09	0.16	0.30	0.40	0.52	0.68
Corporate and Other	(0.13)	0.10	0.04	0.04	0.04	0.04
Total EPS	**3.09**	**3.23**	**3.47**	**3.56**	**3.74**	**3.85**
Growth Rate		*4.4%*	*7.4%*	*2.8%*	*5.0%*	*3.0%*
EPS CAGRs	***2013-2016***	***5.0%***	***2014-2016***	***3.9%***		
Guidance		$3.05 - 3.25	$3.35 - 3.55	$3.30 - 3.60	$3.45 - 3.85	
Consensus		*3.19*	*3.49*	*3.54*		
Prior Estimate		3.23	3.47	3.56	3.74	3.85
Regulated-Only EPS		*2.55*	*2.96*	*3.11*	*3.46*	*3.55*

Source: Company Filings, FactSet, and UBS Estimates

Calpine

We suspect Calpine cleared the bulk of its capacity, however, overall EBITDA was largely unchanged YoY, although is a modest positive revision vs. our expectations of $80/MW-day originally. We look for shares here to respond positively to the signal of strong new market entrant seen in the PJM auction, reaffirming the value of CCGT units in the PJM footprint.

$35Mn capacity revenue increase in 2017.

Calpine 2017E capacity revenue increases 18% from $200Mn to ~$235Mn which flows directly to Adjusted EBITDA; however, this is offset by declines in power pricing.

Figure 17: CPN Earnings Estimate Summary

Calpine Adj. EBITDA UBSe	2012	2013	2014	2015	2016	2017	2018
West	638	684	778	688	700	680	699
Texas	323	356	407	578	578	632	666
Southeast	102	80	116	17	14	12	12
North	590	615	683	651	552	526	573
Other	33	29	30	29	30	31	31
Corporate Allocation	63	66	54	67	68	70	72
Total EBITDA	**1,749**	**1,830**	**2,068**	**2,031**	**1,942**	**1,951**	**2,053**
Guidance	*1,800-1,825*	*1,900-2,000*					
Street Consensus (5/24/14)			*1,986*	*2,038*	*2,050*	*2,196*	
Previous UBS			*2,068*	*2,052*	*1,942*	*1,967*	

Source: Company Filings, ThompsonReuters, and UBS Estimates

Dynegy

The PJM capacity uplift does help 2017e adjusted EBITDA but Dynegy remains among the most sensitive to power prices and our adjusted EBITDA is declining 12/13% in 2015/2016 due to the pullback of power. Consensus estimates have climbed significantly in the past two weeks and we still see a positive outlook for shares despite the recent decline in estimates.

Despite owning just two CCGTs (~2GW) and having ~840 MW of transmission import rights into PJM from the IPH portfolio, the company remains among the most sensitive to the uplift in the auction.

Figure 18: Dynegy estimates update

Pro-Forma Dynegy-Ameren Estimates	2013A	2014E	2015E	2016E	2017E	2018E
Midwest (Dynegy Inc.)	50	215	193	206	213	207
West	95	49	46	52	7	8
Northeast	137	186	146	131	140	168
Illinois Power Holdings (Standalone)	12	74	81	113	149	163
PRIDE Reloaded (Mostly Gross Margin/Not O&M)			48	85	85	85
Consolidated G&A	(76)	(100)	(100)	(100)	(100)	(100)
Adj. EBITDA (Standalone DYN + IPH)	219	425	413	486	494	530
UBS Prior		425	472	548	529	561
Consensus (5/24/14)		*390*	*533*	*558*		
Guidance	200 - 225	300-350				
CoalCo	(10) - 15					
GasCO	280 - 295					
Adj. EBITDA w/ o G&A Allocation	283	525	465	501	509	545
CoalCo	(14)	133	51	71	76	73
GasCo	296	317	334	318	283	309
Illinois Power Holdings		74	81	113	149	163

Source: Company reports and UBS estimates

Exelon:

For EXC's fleet we had assumed $703Mn of capacity payments in 2017 based upon an $80/MW-Day clearing price which increases significantly to ~$900Mn, driving ~$0.15/sh EPS improvement. We suspect some (up to ~5GW) did not clear in either the Eastern or Western footprint, significantly muting this uplift, with 4.225GW of this from its nuclear portfolio not clearing. This is offset partially for our estimates by declines in power prices since our previous update at the start of May (ex. PJM-West ATC 2017 declined ~$1.75 MTD).

Figure 19: EXC Earnings Estimate Summary

Exelon Consolidated EPS	2012A	2013A	2014	2015	2016	2017	2018
PECO	0.47	0.46	0.46	0.47	0.48	0.50	0.53
ComEd	0.47	0.49	0.56	0.63	0.66	0.70	0.75
BGE	0.06	0.23	0.22	0.22	0.22	0.24	0.25
Exelon Generation	1.89	1.40	1.21	1.35	1.26	1.60	1.71
Other	(0.04)	(0.07)	(0.06)	(0.10)	(0.14)	(0.15)	(0.16)
Total EPS	**2.85**	**2.50**	**2.38**	**2.56**	**2.49**	**2.89**	**3.08**
Guidance			**2.25-2.55**				
Consensus			2.37	2.34	2.23	2.33	-
Prior UBS estimates		*2.50*	*2.38*	*2.62*	*2.54*	*2.80*	*2.95*
Regulated EPS		*1.17*	*1.24*	*1.31*	*1.37*	*1.44*	*1.53*
Regulated Guidance			*1.10-1.40*	*1.15-1.45*	*1.25-1.55*		

Source: Company Filings, FactSet, and UBS Estimates

What units didn't clear? We know at least some of the nuclear units didn't

(1) Quad Cities: 1.3GW owned by EXC (75% of the total 2-unit plant)

(2) Byron: 2.3GW plant. This 2-unit site was discussed by

(3) Oyster Creek: 625 MW in EMAAC. It appears the company could yet retire the unit early given current power market and incremental auction capacity trends (vs. its negotiated 2019 retirement with the state of NJ over 316(b) rule compliance).

We believe it is likely that Exelon did not clear additional units as well – details could yet be provided in the follow-up fuel report to be released by PJM in the week ahead.

FirstEnergy

FirstEnergy's fleet sees its 2017E capacity revenues increase $100Mn from $315Mn to ~$415Mn as a result of the increase from $80/MW-Day to $120MW-Day **(~$0.15/sh EPS impact),** again as mentioned with Exelon above, the increase in our 2017 estimates is halved by a modest reduction in power prices. The decline in power prices MTD has driven the ~4% reduction in our 2015/2016 estimates.

We continue to estimate FE cleared only a fraction of its existing supply in the ATSI zone, at just ~4GW, versus its total footprint of 7.6GW in the ATSI Zone. We suspect FE likely also moved not to clear some of its RTO capacity as well, seeing its overall footprint in the market at 13GW, sufficiently large as to warrant a portfolio bidding approach. Our estimates reflect the fact that company did not clear

Figure 20: FE Earnings Estimate Summary

UBS Estimates	2013E	*2014 Guidance*	2014E	2015E	2016E	2017E	2018E
Energy Delivery	2.03	*1.98-2.04*	2.02	2.05	2.09	2.12	2.18
FirstEnergy Solutions	0.73	*0.12-0.22*	0.13	0.53	0.29	0.19	0.31
Transmission (ATSI, Trail, and OpCo's)	0.47	*0.52-0.56*	0.52	0.54	0.71	0.80	0.86
Other	(0.20)	*(0.22)*	(0.22)	(0.15)	(0.17)	(0.19)	(0.22)
Total UBSe EPS	3.04	*2.40-2.60*	2.45	2.98	2.92	2.93	3.13
Previous UBSe (except Guidance)		*2.45-2.85*	2.47	3.15	3.06	2.90	
Consensus			2.48	3.00	2.90	2.74	3.30

Source: Company Filings, FactSet, and UBS Estimates

We include our latest estimate of capacity payments for FE, which suggests payments reach a low in 2018. We suspect FE will continue to clear a limited quantity of MWs in future auctions.

Figure 21: FirstEnergy Gross Margin Composition by year

Gross Margin	2013	2014	2015	2016	2017	2018
Open Coal Energy Margins	322	393	635	638	707	715
Open Nuclear Energy Margins	730	761	877	905	933	943
Hedge Value (From Analyst Day+MtM Sinc	805	411	(255)	(144)		
Capacity Revenues	237	406	929	668	387	438
Marketing Margin (UBSe Retail Margins)	259	1	100	100	100	100
Gross Margin (Gen/Retail-Only)	2,352	1,972	2,285	2,167	2,126	2,197

Source: Company Filings and UBS Estimates

We include our updated EBITDA projections below. We suspect FE is at or below the low end of its 2015 EBITDA guidance range given the latest MtM effect of power forwards as well as reduced marketing ambitions – we look for an update (likely with a slightly lower range) in the coming quarter.

Figure 22: FirstEnergy EBITDA Composition

EBITDA	2013	2014	2015	2016	2017	2018
Open Fossil EBITDA	(74)	114	810	574	352	538
Open Nuclear EBITDA	41.12	169	329	245	276	320
Retail & Hedges EBITDA	1,262	332	(237)	(42)	102	(65)
FES Total	1,229	616	902	777	730	793
Adjusted EBITDA Guidance		615-655	$950-$1,050			

Source: Company Filings, FactSet, and UBS Estimates

PEG:

Our estimate of PSEG 2017e capacity revenues inched higher from $625Mn to ~$660Mn. We suspect PSEG continued to clear the bulk of its capacity in its region.

Figure 23: PSEG Earnings Estimate Summary

	2012A	2013A	2014E	2015E	2016E	2017E
PSEG Power	1.27	1.40	1.28	0.97	0.85	0.88
PSE&G	1.04	1.21	1.41	1.57	1.74	1.90
PSEG Enterprise & Other	0.13	(0.03)	0.07	0.09	0.11	0.11
Total	***2.44***	***2.58***	***2.77***	***2.62***	***2.71***	***2.90***
Prior	2.44	2.58	2.77	2.64	2.74	2.89
Consensus			2.76	2.67	2.73	
% Regulated	43%	47%	51%	60%	64%	66%
Regulated EPS CAGR ('13-16')					13%	
Guidance	**$2.40-$2.55**	**$2.55-$2.75**				

Source: Company Filings, FactSet, and UBS Estimates

PPL:

Our estimate of PPL Energy Supply 2017e capacity revenues jumped from $322Mn to $400Mn. Given our expectations for a spin or sale of the Supply business, we suspect PPL cleared the bulk of its capacity despite the ability to bid in a materially higher ACR across its coal units (hence the reason why PJM appears to have opted to model PPL as a separate zone).

Notably, PPL Zone was the only region to have both Limited DR and Summer Extended clear at a separate price.

Figure 24: PPL Earnings Estimate Summary

PPL Corp. UBSe EPS	2013E	2014E	2015E	2016E	2017E	2018E	13-'17 CAGR
Energy Supply	0.39	0.11	0.07	0.11	0.10	0.14	
UK Utilities	1.37	1.37	1.44	1.50	1.51	1.57	2.5%
PA Electric Utility	0.32	0.38	0.41	0.45	0.49	0.53	10.9%
Kentucky Utilities	0.48	0.43	0.53	0.50	0.60	0.57	5.8%
Corporate	(0.11)	(0.06)	(0.04)	(0.12)	(0.16)	(0.21)	
Total	**2.45**	**2.23**	**2.40**	**2.43**	**2.54**	**2.61**	
Guidance Range	2.30-2.40	2.15 - 2.30					
UK Utilities Guidance (Juy '13)	1.25-1.32	1.19-1.31	1.17-1.33				
Prior UBSe	2.45	2.22	2.43	2.51	2.51		
Street Consensus	2.45	2.24	2.24	2.24	2.24		

Source: Company Filings and UBS Estimates

And digging into the PPL Supply portfolio, positive FCF remains, however, we suspect traditional EV/EBITDA multiples ascribe too much value to the segment given the more limited FCF profile of the assets.

Figure 25: PPL Supply – Updated Projections

PPL Supply Projections	2011A	2012A	2013A	2014E	2015E	2016E	2017E	2018E
Generation EBITDA	1,311	1,257	856	576	561	659	621	646
Nuclear D&A	119	112	132	148	152	157	161	166
Interest Expense -- PPL Supply Only	(160)	(160)	(153)	(118)	(118)	(118)	(118)	(118)
Taxes (Est.)	(515)	(255)	(138)	(39)	(31)	(64)	(55)	(67)
FCF pre-capex (proxy for FFO)	755	953	697	567	564	634	609	627
Growth/Other Capex								
Base Capex	507	197	197	101	100	250	250	250
Nuclear Fuel	152	159	161	158	160	160	160	160
Environmental	181	314	89	354	295	0	0	0
Other	0	230	253	(83)	(45)	20	20	20
Total Growth/Other Capex	840	900	700	530	510	430	430	430
Free Cash Flow	(85)	53	(3)	37	54	204	179	197
Debt Profile (incl. ST Debt Balance)	3,424	3,628	2,525	3,192	3,192	3,192	3,192	3,192
Cash	(379)	(413)	(551)	(588)	(642)	(847)	(1,026)	(1,223)
Net Debt	3,045	3,215	1,974	2,604	2,550	2,345	2,166	1,969
Equity Unit Conversions				978				
Sale Proceeds (Back to the parent)			895					
Colstrip Debt			273					
Maturities (From 1Q14 Slides)			438	303	304	354	4	403
Net Debt/EBITDA	4.0x	3.4x	2.8x	4.6x	4.5x	3.7x	3.6x	3.1x
FFO / Debt	22%	26%	28%	18%	18%	20%	19%	20%
Moodys Target for Supply			20%					

Positive Free Cash Flow Forecast

Source: Company reports and UBS estimates

NRG

GenOn: How much capacity cleared – and potentially additions too?

We include our updated GenOn estimates below. Here too we have not discounted the total cleared. It remains unclear how much capacity on the GenOn side did not clear – we look to updates on the forward looking capacity revenue disclosures with 2Q results (we don't anticipate NRG will provide much clarity beyond this). Meanwhile, it is unclear to what extent the company was able to clear further capacity reactivations – specifically Shawville (PA) and Portland (NJ) as conversions using the existing steam boilers used for coal (they had been both slated to shut due to MATS compliance).

The latest auction appears positive for GenOn on paper – with supportive pricing and possibility of even newly reactivated capacity

That said, we see further gas plant additions, particularly in Maryland – both clearing in the latest auction as well as future potential plans as concerning over the future of the assets. It is also unclear if NRG continued to clear its Chalk Point and Dickerson units (despite its decision not to deactivate), seeing the broader uplift accruing to remaining units.

The longer-term outlook remains less clear for GenOn

Liquidity appears sufficient through medium term

Figure 26: GenOn segment – Revised with latest forwards & capacity payments (assuming cleared auction).

GenOn Mini Free Cash Flow	2013A	2014E	2015E	2016E	2017E	2018E
Beginning Cash Balance	825	760	674	771	801	855
EBITDA	482	548	568	534	559	626
Plus: Non-Cash Lease Amortization	80	80	80	80	80	80
Less: Minimum Lease Payment	(202)	(194)	(166)	(211)	(207)	(196)
Interest Expense	(205)	(262)	(262)	(262)	(262)	(282)
Maintenance Capex	138	115	115	110	115	115
Environmental Capex	118	142	7	0	0	0
Total Capex	256	257	122	110	115	115
Free Cash Flow	(101)	(86)	97	30	54	112
Ending Cash Balance	724	674	771	801	855	967

Source: Company reports and UBS estimates

… and how about EME's Midwest Generation portfolio?

We attribute a huge slug of the improvement in PJM to NRG's likely decision not to clear the bulk of its recently acquired Midwest generation portfolio as part of its EME acquisition. Given even the modest contemplated retrofits necessary to achieve compliance with IL MPS requirements, which ratchet up in 2017 for EME, we believe the company has likely opted to remove the plants – driving up broader capacity prices, a net benefit for its portfolio. We look for an update on total plant O&M and synergy contributions in coming quarters- as well as an overall portfolio update on unit plans.

What does NRG intend to do with EME? Synergies and plan has yet to be disclosed.

Dominion:

The impact of the capacity estimates was largely immaterial; however, the power price improvement drove gains for Merchant Generation relative to our last commodity update. For example, 2016 Merchant Generation EBIT increased from $345Mn to $418Mn.

Improvement for Dominion driven by relatively stale commodity numbers relative to peers.

Figure 27: D Earnings Estimate Summary

2014 Guidance vs 2013 Actual Results and UBS 2014E								
Estimates by Segment (EBIT) using ABS								
		FY14 Guidance			UBS			
VEPCO	**2013A**	**Low**	**High**	**2014 Mid**	**2014E**	**2015E**	**2016E**	**2017E**
Electric Distribution	542	590	615	603	604	664	703	724
Electric Transmission	402	460	480	470	478	558	613	664
Utility Generation	1,293	1,435	1,485	1,460	1,456	1,525	1,578	1,658
Virginia Power - Corp Adjusted	-	-	-	-	-	-	-	-
VEPCO Adjusted EBIT	**2,237**	**2,485**	**2,580**	**2,533**	**2,538**	**2,746**	**2,894**	**3,047**
Regulated Gas Ops								
Gas Distribution	242	235	245	240	240	266	288	310
Gas Transmission (Incl. Caiman)	834	780	810	795	808	891	944	943
Total Regulated Gas	**1,076**	**1,015**	**1,055**	**1,035**	**1,048**	**1,157**	**1,232**	**1,252**
Merchant Generation	341	315	360	338	340	471	418	507
Dominion Retail	115	55	65	60	62	62	62	62
Corp & Other	(45)	(35)	-	(18)	(10)	(1)	68	418
Total Adjust EBIT	**3,724**	**3,835**	**4,060**	**3,948**	**3,977**	**4,435**	**4,674**	**5,287**
Interest expense	870	935	925	930	934	987	1,018	1,069
Income Taxes	950	950	970	960	968	1,120	1,206	1,392
Non-controlling Interests	23	25	15	20	20	20	20	20
Operating Earnings	**1,881**	**1,925**	**2,150**	**2,038**	**2,055**	**2,307**	**2,429**	**2,806**
Shares Outstanding	580	584	582	583	585	589	599	613
EPS	**3.25**	**3.30**	**3.69**	**3.50**	**3.52**	**3.92**	**4.06**	**4.58**
Previous UBS Estimates					**3.52**	**3.86**	**3.99**	**4.51**
Formal EPS Guidance Range		**3.35**	**3.65**	**3.35-3.65**				
Guidance of 5%-6% growth off 2011 3.05 base minus 0.04 for elec retail				**3.53**	**3.53**	**3.73**	**3.93**	
Growth Rate of UBS Estimates						**11.4%**	**3.6%**	**12.8%**
Consensus					**3.55**	**3.76**	**3.94**	**4.13**

Source: Company Filings and UBS Estimates

Entergy:

While Entergy does not have the PJM exposure like the other names, we have updated our estimates for the latest commodity prices. Our Entergy estimates were last updated in April versus May for many of the companies above therefore the power estimates are higher in 2015+. We flag New England prices remain high due to expectations for continued supply bottlenecks of gas during winter peaking periods.

Figure 28: ETR Earnings Estimate Summary

EPS by Segment	2012A	2013A	2014E	2015E	2016E	2017E	2018E
Regulated Utility	5.50	4.80	5.03	5.23	5.39	5.57	5.76
EWC/Nuclear	1.49	1.47	2.13	0.73	0.69	0.26	0.21
Other	(0.76)	(0.91)	(1.10)	(0.96)	(0.92)	(0.96)	(1.00)
Consolidated	6.23	5.36	6.05	5.00	5.16	4.87	4.96
Previous	6.23	5.36	6.05	4.87	4.94	4.52	
Guidance Range		*4.60-5.40*	*5.55-6.75*				
Consensus			*6.04*	*5.12*	*5.11*	*5.23*	

Source: Company Filings and UBS Estimates

Statement of Risk

Risks for Utilities and Independent Power Producers (IPPs) primarily relate to volatile commodity prices for power, natural gas, and coal. Risks to IPPs also stem from load variability, and operational risk in running these facilities. Rising coal and, to a certain extent, uranium prices could pressure margins as the fuel hedges roll off Competitive Integrateds. Further, IPPs face declining revenues as in the money power and gas hedges roll off. Other non-regulated risks include weather and for some, foreign currency risk, which again must be diligently accounted in the company's risk management operations. Major external factors, which affect our valuation, are environmental risks. Environmental capex. could escalate if stricter emission standards are implemented. We believe a nuclear accident or a change in the Nuclear Regulatory Commission/Environment Protection Agency regulations could have a negative impact on our estimates.

Risks for regulated utilities include the uncertainty around the composition of state regulatory Commissions, adverse regulatory changes, unfavorable weather conditions, variance from normal population growth, and changes in customer mix. Changes in macroeconomic factors will affect customer additions/subtractions and usage patterns

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Buy	FSR is > 6% above the MRA.	47%	33%
Neutral	FSR is between -6% and 6% of the MRA.	42%	34%
Sell	FSR is > 6% below the MRA.	11%	23%
UBS Short-Term Rating	**Definition**	**Coverage[3]**	**IB Services[4]**
Buy	Stock price expected to rise within three months from the time the rating was assigned because of a specific catalyst or event.	less than 1%	less than 1%
Sell	Stock price expected to fall within three months from the time the rating was assigned because of a specific catalyst or event.	less than 1%	less than 1%

Source: UBS. Rating allocations are as of 31 March 2014.
1:Percentage of companies under coverage globally within the 12-month rating category. 2:Percentage of companies within the 12-month rating category for which investment banking (IB) services were provided within the past 12 months.
3:Percentage of companies under coverage globally within the Short-Term rating category. 4:Percentage of companies within the Short-Term rating category for which investment banking (IB) services were provided within the past 12 months.

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Company Disclosures

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AES Corporation[2, 4, 6a, 16]	AES.N	Neutral	N/A	US$13.61	23 May 2014
American Electric Power, Inc.[4, 6a, 6b, 6c, 7, 16]	AEP.N	Neutral	N/A	US$51.41	23 May 2014
Calpine Corporation[2, 4, 6a, 16]	CPN.N	Neutral	N/A	US$22.42	23 May 2014
Dominion Resources[2, 4, 5, 6a, 6b, 6c, 7, 16]	D.N	Buy	N/A	US$69.32	23 May 2014
Duke Energy[2, 4, 5, 6a, 16]	DUK.N	Buy	N/A	US$70.28	23 May 2014
Dynegy, Inc.[4, 5, 6a, 16]	DYN.N	Buy	N/A	US$31.78	23 May 2014
Entergy Corp.[16]	ETR.N	Sell	N/A	US$74.06	23 May 2014
Exelon Corp.[2, 4, 5, 6a, 6c, 7, 16, 22]	EXC.N	Neutral	N/A	US$34.15	23 May 2014
FirstEnergy Corp.[4, 6a, 16, 22]	FE.N	Neutral	N/A	US$31.48	23 May 2014
NRG Energy Inc.[16]	NRG.N	Buy	N/A	US$33.72	23 May 2014
PPL Corporation[2, 3, 4, 5, 6a, 6c, 7, 16]	PPL.N	Neutral	N/A	US$33.38	23 May 2014
Public Service Enterprise Group[6b, 6c, 7, 16]	PEG.N	Neutral	N/A	US$37.40	23 May 2014

Source: UBS. All prices as of local market close.
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