US IPP Electric Utilities & IPPs

2Q Playbook: Summer Power Outage

Equities

Americas
Electric Utilities

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Lacking confidence, but can the Fall calendar reinvigorate the group?

Overall, it's a less than exciting 2Q earnings seasons, with more misses than beats expected. We see the paucity of positive datapoints sets the entire group up for further relative weakness into summer end. Having said that, assuming weather holds 3Q results and a hyperactive Fall regulatory calendar (highlighted by EPA's carbon rules and PJM, and baseload bailouts) could well reinvigorate expectations into year-end. Power remains in the doldrums, with near-term challenges as MtM pressures have impacted a wide swath of the sector.

Where do we see 2Q opportunities and disappointment?

We see SRE, EXC, ETR, NEE, EIX, PPL, SCG, XEL, ES, and NRG as all potentially benefitting directly from 2Q or events/updates thereabouts. Specifically, we see execution success for NEE and SRE, deal synergy upside for EXC given POM and PPL w/o TLN, and regulatory success for SCG, XEL, ES. Lastly, NRG could surprise with discussion of a still-nascent solar restructuring. We see potential disappointments around SO and DUK most significantly, but also potentially FE, DTE, TE, ITC, PNW, TLN, and WR as also suffering from either direct 2Q misses or from other investor concerns. Potential disappointments appear to be predominantly around weaker normalized sales potential (DUK), coal concerns (TE), capex execution (ITC), and wider regulatory pushback (SO).

Commodity MtM flat to down QoQ, but declining in recent days

While Summer expectations for 2015 – and in turn 2016 have continued to melt of late, overall ATC prices for 2016 were surprisingly flattish QoQ (6/30 vs. 3/31). The question remains whether companies will opt to mark their outlooks at quarter end rather than in mid-July following the latest downturn. We continue to see a bottoming in near-term Henry Hub prices as providing support for Western PRB generators such as NRG and DYN. In contrast, we see potential for further pressure on the Mid-Atlantic. We see 2Q and 3Q as representing a potential peak switching season, meaningfully exceeding levels seen in 2012. On PJM capacity auction, we see the transition auctions as a modest positive, with the actual BRA auction as potentially benign datapoint given robust expectations.

So how are we positioned on the space? Less overall, but value play on power

We are less constructive on the sector into 2Q, with a relative paucity of good updates. Rather, we see the opportunity for the sector as more firmly tied to the 3Q/EEI updates where future capex plans resulting from the Clean Power Plan (CPP) will be much vaunted, padding future capex and EPS growth figures. In the interim, the latest commodity pressures and further scrutiny of solar demand erosion and weaker normalized trends will leave many asking where to find opportunity. For those taking the long view, with the sector now trading at a -5% discount to the S&P, we're more mixed on regulateds, seeing less reason to get involved ahead of an ever nearing potential rate hike. Looking through recent pressure on power, we see FCF yields on IPPs as reaching multi-year highs, reflecting the exceptionally negative sentiment (particularly among commodity investors). We suspect an opportunity for entry may be approaching.

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Earnings and Price Target Snapshots

We reflect changes for companies, indicating EBITDA for IPPs and EPS for Utilities.
We also indicate prospective yield for covered YieldCos.

Figure 1: Changes to Earnings, Price Targets, and Ratings

		Price	Rating		Price target		2015E EPS		2016E EPS		2017E EPS	
Company	**RIC**	**14-Jul-15**	**New**	**Old**	**New**	**Old**	**New**	**Old**	**New**	**Old**	**New**	**Old**
AES Corporation	AES.N	13.12	Neutral	Neutral	**13.00**	14.00	1.27	1.27	**1.27**	1.28	**1.40**	1.42
Ameren	AEE.N	38.86	Neutral	Neutral	**40.00**	41.00	**2.51**	2.48	**2.63**	2.61	**2.78**	2.76
American Electric Po	AEP.N	55.19	Neutral	Neutral	**54.00**	57.00	3.49	3.49	**3.56**	3.57	**3.64**	3.69
Avista	AVA.N	31.82	Neutral	Neutral	**31.00**	33.00	1.92	1.92	2.03	2.03	2.13	2.13
Calpine	CPN.N	17.63	Neutral	Neutral	**19.00**	23.00	**0.81**	0.86	**0.64**	0.75	**0.83**	1.00
CMS Energy	CMS.N	33.76	Buy	Buy	**37.00**	38.00	1.89	1.89	2.02	2.02	2.16	2.16
Consolidated Edison	ED.N	60.42	Sell	Sell	55.00	55.00	**3.96**	3.95	**3.92**	3.91	3.96	3.96
Dominion	D.N	69.20	Buy	Buy	**77.00**	79.00	**3.60**	3.59	**3.87**	3.91	**4.11**	4.14
DTE Energy	DTE.N	77.10	Buy	Buy	93.00	93.00	4.66	4.66	5.00	5.00	5.36	5.36
Duke Energy	DUK.N	73.80	Neutral	Neutral	**79.00**	84.00	**4.60**	4.66	**4.95**	5.00	**5.20**	5.27
Dynegy	DYN.N	29.49	Buy	Buy	**37.00**	40.00	**0.11**	0.37	**0.84**	1.00	**1.04**	1.16
Edison International	EIX.N	57.94	Buy	Buy	**66.00**	70.00	3.60	3.60	3.98	3.98	4.31	4.31
Empire District	EDE.N	22.54	Sell	Sell	**21.00**	22.00	1.38	1.38	1.47	1.47	1.54	1.54
Entergy	ETR.N	72.29	Neutral	Neutral	**76.00**	79.00	**5.47**	5.41	**4.98**	5.10	**5.01**	5.29
Eversource Energy	ES.N	47.30	Neutral	Neutral	**49.00**	53.00	2.80	2.80	2.98	2.98	3.19	3.19
Exelon	EXC.N	32.77	Neutral	Neutral	**33.00**	35.00	**2.43**	2.44	**2.38**	2.42	**2.52**	2.64
FirstEnergy	FE.N	33.62	Sell	Sell	28.00	28.00	2.52	2.52	**2.72**	2.74	**2.23**	2.29
Hannon Armstrong	HASI.N	21.00	Buy	Buy	22.00	22.00	1.10	1.10	1.31	1.31	1.51	1.51
ITC Holdings	ITC.N	33.38	Neutral	Neutral	36.00	36.00	2.06	2.06	2.00	2.00	2.25	2.25
NextEra Energy	NEE.N	101.99	Buy	Buy	**116.00**	118.00	**5.71**	5.72	**6.05**	6.06	**6.49**	6.53
NextEra Energy LP	NEP.N	39.99	Neutral	Neutral	44.00	44.00	1.03	1.03	1.13	1.13	1.14	1.14
NRG Energy	NRG.N	22.08	Buy	Buy	**25.00**	30.00	**2.29**	2.46	**1.54**	1.82	**1.36**	1.70
NRG Yield	NYLDa.N	21.95	Neutral	Neutral	27.00	27.00	1.23	1.23	1.49	1.49	1.54	1.54
PG&E Corp.	PCG.N	51.00	Neutral	Neutral	**54.00**	57.00	3.61	3.61	3.75	3.75	3.68	3.68
Pinnacle West Captl	PNW.N	60.11	Buy	Buy	**65.00**	63.00	3.86	3.86	4.01	4.01	4.24	4.24
PPL Corp.	PPL.N	30.99	Neutral	Neutral	31.00	31.00	2.20	2.20	2.25	2.25	2.25	2.25
Public Service Entrp	PEG.N	40.88	Neutral	Neutral	**41.00**	43.00	2.84	2.84	**2.81**	2.82	**2.81**	2.83
SCANA Corp.	SCG.N	52.78	Neutral	Neutral	**56.00**	55.00	3.69	3.69	3.93	3.93	4.10	4.10
Sempra Energy	SRE.N	101.98	Buy	Buy	**118.00**	120.00	4.80	4.80	**5.04**	5.07	**5.36**	5.40
Southern Company	SO.N	43.21	Sell	Sell	41.00	41.00	2.85	2.85	2.93	2.93	3.03	3.03
Talen Energy	TLN.N	17.72	Sell	Sell	18.00	18.00	**1.57**	1.48	**1.60**	1.68	**0.49**	0.47
TECO Energy	TE.N	18.52	Buy	Buy	**20.00**	22.00	**1.09**	1.10	**1.17**	1.18	**1.30**	1.32
WEC Energy Group	WEC.N	47.22	Neutral	Neutral	**48.00**	49.00	2.75	2.75	2.87	2.87	3.00	3.00
Westar Energy	WR.N	35.93	Neutral	Neutral	**36.00**	38.00	2.26	2.26	2.42	2.42	2.52	2.52
Xcel Energy Inc.	XEL.N	33.54	Neutral	Neutral	**35.00**	36.00	2.09	2.09	**2.22**	2.21	2.34	2.34

Source: FactSet, Company reports, and UBS estimates

Figure 2: Visualizing potential 2Q Beats and Misses

BENCHMARKS	Ticker	2Q15 Earnings Center		
S&P500	SPY	0.1%	2Q15 Performance	
Utilities Select SPDR	XLU	-6.8%	2Q15 Performance	
COMPETITIVE INTEGRATED	**Ticker**	**UBSe**	**Consensus**	**Expected Beat/(Miss)**
American Electric Power, Inc.	AEP	$0.78	$0.79	0%
Dominion Resources	D	$0.70	$0.73	-5%
Entergy Corp.	ETR	$0.96	$1.12	-14%
Exelon Corp.	EXC	$0.53	$0.53	0%
FirstEnergy Corp.	FE	$0.47	$0.47	-2%
NextEra Energy	NEE	$1.52	$1.47	3%
Public Service Enterprise Group	PEG	$0.52	$0.54	-5%
Sempra Energy	SRE	$0.97	$0.99	-2%
Average				-3.1%
REGULATED INTEGRATED UTILITIES	**Ticker**	**UBSe**	**Consensus**	**Expected Beat/(Miss)**
Ameren Corp.	AEE	$0.58	$0.60	-3%
Alliant Energy Corp.	LNT	N/A	$0.61	N/A
Avista Corp	AVA	$0.44	$0.53	-17%
CMS Energy	CMS	$0.28	$0.34	-19%
DTE Energy Co.	DTE	$0.85	$0.82	4%
Duke Energy	DUK	$0.93	$1.04	-12%
Edison International	EIX	$0.79	$0.78	1%
Empire District Electric Company	EDE	$0.21	$0.27	-21%
Great Plains Energy	GXP	N/A	$0.32	N/A
Hawaiian Electric Industries	HE	N/A	$0.41	N/A
PG&E Corporation	PCG	$0.83	$0.71	18%
Pinnacle West Capital Co.	PNW	$1.19	$1.25	-5%
PNM Resources Inc.	PNM	N/A	$0.40	N/A
PPL Corporation	PPL	$0.48	$0.42	13%
SCANA Corp.	SCG	$0.64	$0.62	3%
Southern Company	SO	$0.69	$0.68	1%
TECO Energy Inc.	TE	$0.25	$0.28	-8%
Westar Energy, Inc.	WR	$0.41	$0.45	-9%
Wisconsin Energy Corp.	WEC	$0.56	$0.56	-1%
Xcel Energy Inc.	XEL	$0.39	$0.41	7%
Average				-3.1%
REGULATED T&D UTILITIES	**Ticker**	**UBSe**	**Consensus**	**Expected Beat/(Miss)**
Consolidated Edison	ED	$0.62	$0.62	0%
ITC Holdings Corp	ITC	$0.55	$0.53	4%
Eversource	ES	$0.54	$0.55	-1%
PEPCO Holdings Inc.	POM	N/A	$0.30	N/A
Average				0.9%
INDEPENDENT POWER PRODUCERS	**Ticker**	**UBSe**	**Consensus**	**Expected Beat/(Miss)**
AES Corporation	AES	$0.22	$0.28	-66%
Calpine Corporation	CPN	$383	$405	-5%
Dynegy, Inc.	DYN	$142	$195	-27%
Talen Energy Corp	TLN	$200	$205	-3%
NRG Energy Inc.	NRG	$664	$676	-2%
Average				-20.5%

Source: FactSet, ThomsonReuters, Company Filings, and UBS Estimates

2Q Earnings Cheat Sheet

We include call times and dial-in information as best available through the publishing date. Unannounced dates are FactSet estimates.

Figure 3: 2Q Call Information

Company	Ticker	Earnings Release	Conf Call Date	Phone Number & Passcode
AES Corporation	AES	08/10/2015 Unspecified	08/10/2015 9:00 AM	Dial In:877-201-0168, Passcode 74217721
Ameren Corp.	AEE	07/31/2015 Unspecified	07/31/2015 10:00 AM	N/A
American Electric Power, Inc.	AEP	07/23/2015 Unspecified	07/23/2015 9:00 AM	Dial in: (800) 398-9386; Passcode: 364235
Avista Corp	AVA	08/05/2015 Specific Time	08/05/2015 10:30 AM	Dial In:(800) 708-4539, Passcode 40193445
Calpine Corporation	CPN	07/30/2015 Before Market	07/30/2015 10:00 AM	Dial In:(888) 895-5271, Passcode 40141927
CMS Energy Corporation	CMS	07/23/2015 Specific Time	07/23/2015 8:30 AM	Dial In:647-788-4901, Passcode 66493498
Consolidated Edison	ED	08/06/2015 After Market	N/A	N/A
Dominion Resources	D	08/05/2015 Unspecified	08/05/2015 10:00 AM	Dial In:(877) 410-5657, Passcode Dominion
DTE Energy Co.	DTE	07/24/2015 Before Market	07/24/2015 9:00 AM	Dial In:(888) 572-7026, Passcode 5008098
Duke Energy	DUK	08/06/2015 Specific Time	08/06/2015 10:00 AM	Dial In:877-874-1586, Passcode 2859838
Dynegy, Inc.	DYN	08/05/2015 Unspecified	N/A	N/A
Edison International	EIX	07/30/2015 Unspecified	07/30/2015 4:30 PM	Dial In:800-369-2198, Passcode Edison
Empire District Electric Company	EDE	07/30/2015 Unspecified	N/A	N/A
Entergy Corp.	ETR	08/04/2015 Before Market	08/04/2015 11:00 AM	Dial In:855-893-9849, Passcode 44024303
Exelon Corp.	EXC	07/29/2015 Before Market	07/29/2015 10:00 AM	Dial In:800-690-3108, Passcode 32485457
FirstEnergy Corp.	FE	0731/2015 Before Market	07/31/2015 10:00 AM	Dial In; (877) 269-7756, Passcode: N/A
ITC Holdings Corp	ITC	07/30/2015 Unspecified	N/A	N/A
NextEra Energy	NEE	07/28/2015 Unspecified	N/A	N/A
Eversource Energy	ES	N/A	N/A	N/A
NRG Energy Inc.	NRG	08/06/2015 Unspecified	N/A	N/A
PG&E Corporation	PCG	07/29/2015 Unspecified	07/29/2015 10:00 AM	Dial-in: (800) 971-1685; Passcode: 7214
Pinnacle West Capital Co.	PNW	07/30/2015 Before Market	07/30/2015 12:00 PM	Dial In:(877) 407-8035, Passcode
PPL Corporation	PPL	07/30/2015 Unspecified	N/A	N/A
Public Service Enterprise Group	PEG	07/31/2015 Specific Time	07/31/2015 11:00 AM	Dial In:877-370-7635, Passcode 72301059
SCANA Corp.	SCG	07/30/2015 Before Market	07/30/2015 3:00 PM	Dial In:888-347-3258, Passcode
Sempra Energy	SRE	08/04/2015 Unspecified	N/A	N/A
Southern Company	SO	07/29/2015 Specific Time	07/29/2015 1:00 PM	Dial in: 800 920 5526, Passcode
TECO Energy Inc.	TE	07/30/2015 Before Market	07/30/2015 9:00 AM	Dial in: (877) 427-4548, Passcode 77023375
Westar Energy, Inc.	WR	08/05/2015 Unspecified	N/A	N/A
WEC Energy Group Inc.	WEC	07/29/2015 Before Market	07/29/2015 2:30 PM	N/A
Xcel Energy Inc.	XEL	07/30/2015 Before Market	07/30/2015 10:00 AM	Dial In:877-723-9520, Passcode 5079681

Source: FactSet

The PM Summary of 2Q Results

AES Corp: While we see shares as off their lows for the year, we're keen to see how re-leveraging of Tiete can shift sentiment. For time, shares are still stuck.

Ameren: We look for a slight miss, but see the latest recovery in 30-year as boding well for guidance. All around, a slight downside bias following weaker gas case ROE and another small transmission ROE writedown.

AEP: Utility growth offsets the well telegraphed GenCo decline leaving a flat quarter. 2H15 critical with respect to PJM datapoints and 1Q16 Ohio PPA that will shape valuation of GenCo and influence management's strategic review.

Avista: Exceptionally quiet, with its acquisition strategy on hold.

Calpine: Expect inline results and intact '15 guidance, alongside record switching to prove a positive offset to deeply negative power sentiment. Execution on buyback will also be key to sentiment.

CMS Energy: A slight miss potential, with real focus on legislation, and detailed focus on incentives for customers to return to US service amidst recent uncertainty on air-tightness of compact contemplated

ConEd: We see potential for retail divestment, updates on development, any regulator datapoints on gas main replacement as among most interest, however Harlem explosion risks linger.

Dominion: Expect a discussion on midstream efforts (seemingly constructive) as well as discussion of latest long-term outlook with IRP filed. Inline Quarter.

DTE: Focus on legislation remains key into Fall and through Summer Committee meetings; inline quarter may leave commentary focused on midstream execution once more. While discounted, not an obvious recovery event into 2Q.

Duke: Among the weakest quarters of large utilities given hydro headwinds in brazil still. Despite underperformance,

Dynegy: The key question will be clarification of its recently launched average guidance for '16-'18, which included uplifts for both PJM and MISO. Recent negativity leaves an attractive FCF yield for shares.

Edison International: Slight beat seen, but real focus will be on settlement potential in pending GRC, alongside commentary on ROE. We remain more constructive following latest slide around SONGS uncertainty.

Empire District: Quiet quarter to be driven around subsequent rate case timing and update on transmission expense recovery.

Entergy: Execution around regulated plan remains critical, most notably in AR given pending case. Potential upside around revised transmission spend outlook following out-of-cycle MISO revisions.

Exelon: Inline quarter leaves bulk of focus on forthcoming ~August close of POM deal as well as Illinois nuclear retirements as upside to story in 2H.

FirstEnergy: We see inline quarter, acceleration of coal-to-gas, and delay in Ohio PPA timeline and implicitly Analyst Day could be offset by PJM transition

auction dynamics remains a real upside uncertainty.

ITC: *The focus will remain on capex rather than regulatory initiatives, seeing continued headwinds to its recently kicked off Lake Erie project.*

NextEra Energy: *We see 2Q as nicely ahead of Street, potential for final bouts of large renewable announcements into PTC/ITC expiration, amidst overhang of M&A uncertainty following seemingly failed bid for Oncor.*

Northeast Utilities: *Focus will remain on receipt of EIS for Northern Pass in July, beyond inline quarter. Discussion could yet migrate towards renewable RFP as a potential catalyst to bolster project credibility. Big developments are in '16.*

NRG Energy: *We see potential discussion of solar company restructuring as complementing wider potential bottoming out in Texas generation and gas expectations.*

PG&E Corp: *Expect a low quality beat, with key focus on latest GT&S delay, commentary on div growth given greater balance sheet visibility, and any speculation on further ROE extension in 2H.*

Pinnacle West: *Weaker weather could drag on concerns around normalized sales growth; update on own solar rooftop initiative could be positive offset.*

PPL: *More constructive as synergy up as first stand-alone call post Talen spin could yield constructive update beyond inline quarter.*

PSEG: We see limited upside for shares as PSEG doesn't benefit from transition auctions, and could see flat to down on full base capacity auction results.

SCANA: *We look for mgmt to extoll recent benefits of its regulatory deal, lending some modest support to shares, alongside possible modest beat.*

Sempra: *Shift in SoCal Gas recognition will make 2Q noisy, but see recent success on Mexican pipelines and LNG exports as boding well. Sets up nicely into 2H around execution of further such contracting efforts.*

Southern Company: *Expect focus to revolve around cash flow and balance sheet impacts from latest rate uncertainty in MS. Potential offset would be discussion of solar asset sale proceeds.*

Talen: *Focus will be on cash deployment and divestment process, but with story known it's hard to see what will be new; a wildcard could yet be developments for the sale of its interest in MT coal plant, Colstrip.*

TECO: *The focus revolves mainly around mgmt's latest efforts to divest the coal business and associated write-down with 2Q (talks remain ongoing), beyond a slight miss on 2Q.*

Westar Energy: *We remain more cautious given a weaker 2Q risk, and potential for ROE reduction. We suspect we may be approaching a relative bottom for shares following Staff's ROE comments in the current case.*

Wisconsin Energy: *We expect an inline quarter to be overshadowed by conversation around EPS guidance.*

Xcel: *Slight miss, but discuss of latest legislative wins in MN could be a benefit*

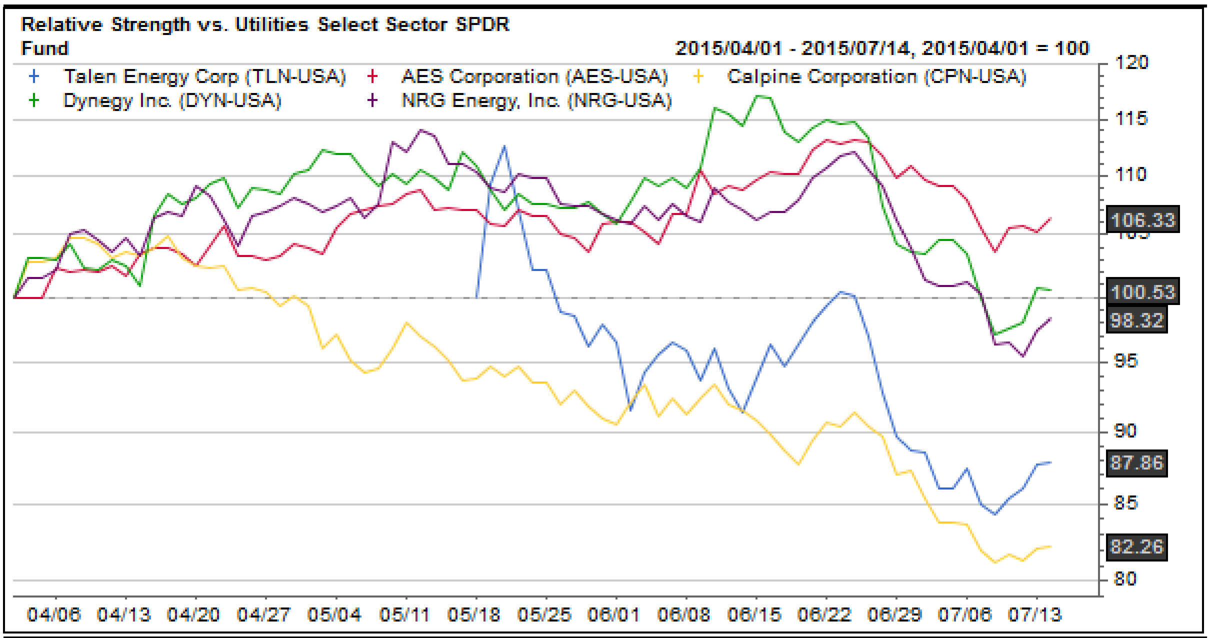
2Q15 Themes: The Latest in Power & Utilities

We include key issues likely to face Power & Utility companies into 2Q results.

- **Giving up on summer already? Energy commodity trends set the stage for challenging 2015:** As we detail in the subsequent market-by-market review, power and natural gas prices have contracted sharply in recent months, pressuring earnings for IPPs and integrated firms. These multi-year low power prices in PJM and Texas have driven IPPs lower since 1Q. AES and DYN are the only two IPPs that have outperformed the XLU since April 1st although both have sold-off in recent weeks as well. Calpine has taken the brunt of the pain due to its Texas exposure. Texas on the cusp of its first real heat of the year (forecasted high of 96-98°F from July 15-22 in Houston) but the peak Operating Reserve Demand Curve (ORDC) pricing might not kick-in without 100°F+ weather.

  Regulated names face a mixed picture with early Midwest summer weather including above-average rainfall and subdued temperature while the East has held up (so far).

Figure 4: IPP Performance (April 1-Present)



Source: FactSet

- **Industry remains singularly focused on carbon compliance… you should too:** Among the clearest priorities from our recent regulator/RTO/executives mini-conference remains how the Clean Power Plan (CPP) will impact their respective states and business. We reiterate our belief this single issue will shape much of our future understanding of the sector in the months ahead – we suggest utility investor see opportunities through the lens of eventual carbon regulations. While some states will take an initial just say 'no' strategy, other appear poised to attempt to comply with preliminary investments already driving utility strategies (eg- efforts led by Dominion for the Atlantic coast Pipeline). We clearly anticipate delineation of respective utility strategies will remain the primary topic this Fall, heading into the annual EEI. Amidst continued uncertainty on utility load growth and concerns over DG growth, we emphasize the opportunity for a reacceleration

in renewables, gas infrastructure, and electric transmission remains of the essence for later in the decade.

Beyond just the focus on carbon, we expect an increasingly articulate discussion around utility-scale renewable strategies in a post-ITC world, alongside even discussion for rooftop solar initiatives directly by utilities themselves (could SO and DUK follow PNW's example?). In contrast, we suspect the mania around storage to die down in the latest quarter.

- **Calm before the regulatory storm:** The upcoming month and balance of 2015 could shape the power markets in a way that few periods have in recent years. Between the Capacity Performance datapoints, Ohio ESP, Illinois potential legislation, and the aforementioned Clean Power Plan we see new reforms leaving their mark on the generation mix for years to come. While these items have less of a dramatic macro impact there are significant rate cases in process in Pennsylvania (EXC/PPL), Kansas (WR/GXP), and Michigan (CMS/DTE) plus the potential for energy reform legislation in Michigan as well. These items are expected to have key developments in the upcoming months to watch for. For Southern Company the upcoming Mississippi rate case looms large if a settlement cannot be reached with a potential rate reduction followed by a 40% increase likely to be unpalatable politically – expect activity in the next few months. Empire District Electric (EDE) is still on track to file its next Missouri rate case in 4Q15 as another one to watch.

PJM auction results, Ohio ESP, and Illinois legislation could all have significant impacts on the generation mix.

Other larger rate cases are pending in Kansas, Michigan, and Pennsylvania.

Figure 5: Select Pending Electric Rate Cases

State	Company	Ticker	Case Identification	Rate Increase ($M)	ROE (%)	Action Likely By
Kansas	Kansas City Power & Light	GXP	D-15-KCPE-116-RTS	$56	10.30	9/10/2015
Kansas	Westar Energy Inc.	WR	D-15-WSEE-115-RTS	$251	10.00	10/28/2015
Michigan	Consumers Energy Co.	CMS	C-U-17735	$196	10.70	12/7/2015
Michigan	DTE Electric Co.	DTE	C-U-17767	$370	10.75	12/21/2015
Missouri	Kansas City Power & Light	GXP	C-ER-2014-0370	$121	10.30	9/29/2015
Pennsylvania	PECO Energy Co.	EXC	D-R-2015-2468981	$190	10.95	12/26/2015
Pennsylvania	PPL Electric Utilities Corp.	PPL	D-R-2015-2469275	$168	10.95	1/1/2016

Source: SNL Energy

- **Distribution is hot, Transmission is not:** With transmission capex growth slowing in the interim, we see utilities tactically refocusing on their distribution networks. On the gas side, main replacement acceleration has been a recent theme with CMS and DTE in Michigan and PSE&G in New Jersey. We expect ConEd to make steps in this direction, potentially doubling its ~$200Mn annual spending to replace 70-miles per year of unprotected steel and cast iron pipes. ConEd currently has a ~35-year forecasted timeframe to replace its pipeline system, the second slowest next to Philadelphia Gas Works. Other companies with forecasted replacement cycles over twenty years include PECO, BG&E, and National Grid NY. Further details are available in our recent report **'Mining for Nuggets at the Western AGA Conference'.**

ConEd could be the latest utility to propose accelerated gas main replacement.

The Northeast remains the 'hotspot' with the oldest gas infrastructure

- **MATS uncertainty still a non-factor:** We surveyed our companies under coverage in 1Q (before the Supreme Court decision) and in 2Q (after) and while the final fate of MATS is still to be determined, the vast majority of utilities do not anticipate a change in their compliance plans. We expect virtually all companies addressing this on their calls with the focus being on (1) potential FCF benefits from delays/deferrals of capex if MATS is

NRG and FE are two of the companies with the most capacity current on MATS waivers.

overturned and (2) the possibility to bring back some shuttered capacity if the energy/capacity signals are right.

- **We may have to wait for PJM transition auction winners and losers:** The results for the 2016/2017 PJM transition auction are set for release on July 30th sandwiched between Exelon (July 29th) and FirstEnergy (31st) with Calpine reporting earnings on the same day. While we expect all exposed companies to address the potential opportunity for the incremental auctions, we estimate the most upside for **FirstEnergy** and look for management to disclose the results on its call the next day (DYN has already partially reflected this in guidance – and in turn expectations). The 2017/208 auction results will be posted on August 6th will be too late for EXC, FE, and perhaps most of the group except for AES and TLN which are slated to report August 10/11.

PJM Auction Results Date:
2016/2017 Trans: July 30
2017/2018 Trans: Aug 6
2018/2019 BRA: Aug 21

Figure 6: Estimated EPS/EBITDA Impact for PJM 2016/2017 2017/18 CP Incremental Auctions

Comparative Impact (EPS & EBITDA)	Total RTO	UBSe 2016 Est	% Impact
DYN (EBITDA)	$ 169	$ 1,395	12%
AEP	$ 0.19	$ 3.69	5%
FE	$ 0.27	$ 2.29	12%
EXC	$ 0.23	$ 2.64	9%
NRG (EBITDA)	$ 113	$ 2,858	4%
AES	$ 0.05	$ 1.42	4%

Comparative Impact (EPS & EBITDA)	Total RTO	UBSe 2017 Est	% Impact
DYN (EBITDA)	$ -	$ 1,395	0%
AEP	$ -	$ 3.69	0%
FE (Includes Uncleared)	$ 0.15	$ 2.29	7%
EXC (Includes Uncleared)	$ 0.12	$ 2.64	5%
NRG	$ -	$ 1.70	0%
AES	$ -	$ 1.42	0%

Source: Company Filings, PJM, SNL, and UBS Estimates

- **Coal-to-gas trends apply even more pressure:** With MATS environmentally-driven coal plant retirements now fully baked in as of the April 15th deadline, we have seen further declines for 2015 (forward) gas pricing at TETCO M3, Transco Zone 6, and Dominion South Pt since our March update. Transco Zone-6 (non-NY) has also broken down noticeably as well, a major supply point for PJM. These zones remain far below the historical spot for 2012, which was the last period of substantial coal-to-gas switching. We believe we are approaching a low in at least power price and specifically Henry Hub gas price expectations in the mid $2s/MMBtu – and as such, see some greater comfort in gas-exposed equities.

The question is how much worse can gas get? Not so much, in our view.

- **Any more transmission ROEs surprises forthcoming?:** Westar surprised the market with 1Q15 results when it took a transmission charge in its pending Kansas Corporation Commission (KCC) FERC challenge and we question whether additional charges are coming this quarter for peers. Westar agreed to a settlement with the KCC for a 10.3% ROE (9.8% base ROE plus a 50bp adder for RTO participation). While we are still waiting for an ALJ proposed decision in the MISO ROE proceedings, we see exposed equities still having an unrecorded liability outstanding for the delta between the New England outcome and ~9.8% from our latest mark-to-market.

Accounting/legal teams will need to assess whether there is enough new information since last quarter to trigger further refinements. The most likely candidate for an adjustment is **FirstEnergy** which still is in the process of settlement talks for its ATSI ROE.

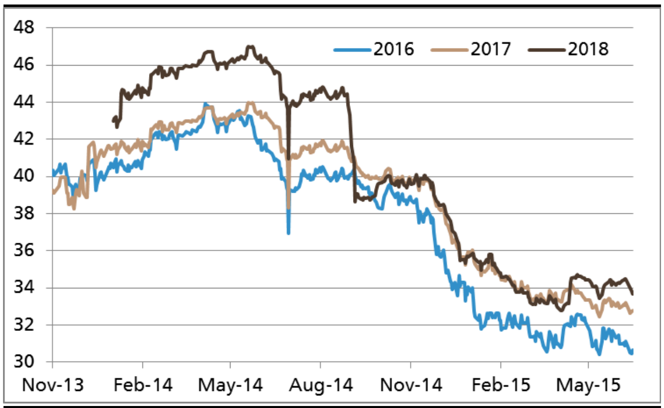
All this said, we have greater confidence the FERC has likely found a new 'low' in its methodology, largely setting rates no lower than the average level for states (seemingly implicit by its adoption of a new base ROE for most latest cases at 9.8% + 50bp for RTO participation). We expect some level of consistency in rate setting on pending cases.

Nuclear units in Texas especially feel the pain of lower power prices.

- **Meltdown in ERCOT?:** With ERCOT's emphasis on the (Operating Reserve Demand Curve) ORDC to reinvigorate power prices when the demand signals are right, we see pressure on the state's four nuclear units (4) representing 5GW of capacity and 9% of electrical generation from the recent decline in power prices. Generators have pursued strategic mothballing and other tactics in Texas to reduce exposure to shoulder months but nuclear units do not have that luxury. From 2011-2013 the average fuel, capital, and O&M cost for nuclear units was $44/MWh, a contrast to the recent ATC power prices in Houston and North Texas. We look towards NRG for commentary on the impact on its nuclear capacity. The two nuclear plants in the state are:

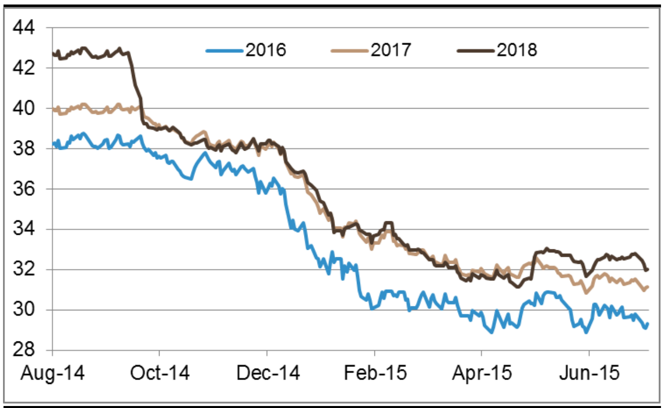
- South Texas Project (2.6GW [44% owned by NRG] in Matagorda ~Houston)
- Comanche Peak (2.4GW [100% owned by EFH] in Somervell ~Dallas)

Figure 7: ERCOT-Houston ATC Pricing ($/MWh)



Source: Platts

Figure 8: ERCOT-North ATC Pricing ($/MWh)



Source: Platts

- **Power markets – General bias remains to help out where possible:** We continue to sense a bias among regulators to sustain compensation for energy and capacity markets alike, consistent with recent decisions to approve PJM's Capacity Performance (CP) scheme, hike the implicit price floor for New England (dynamic delist set at $5.50/kW-mo or $180/MW-day, up from $3.94/mo previously). Moreover, we see widespread support for the higher price trends despite recent critique of price spikes; we see MISO as positioned to actually raise their reference price levels, rather than move away from the mechanism that allowed Illinois/Zone 4 to clear notably higher than adjacent zones. Lastly, we see some willingness to revisit the ORDC scarcity price methodology in ERCOT; specifically, allowing demand to set LMP would appear to be a modestly bullish. Lastly, we see stakeholders as more meaningfully pushing efforts around PJM energy market 'price formation' rules following success on CP reforms for capacity markets. While hard to quantify, expect much more on this from FERC in coming months too – specifically Staff. In contrast, re-evaluation of chronic over-forecasting of load methodology by PJM could well results in substantial offsets to CP benefits.

Expect continued regulatory support for power

PJM to look at power market improvements now?

Recently increased price cap for ISO-NE

MISO could *raise* p rice caps?

ERCOT could seek some tweaks to setting price cap

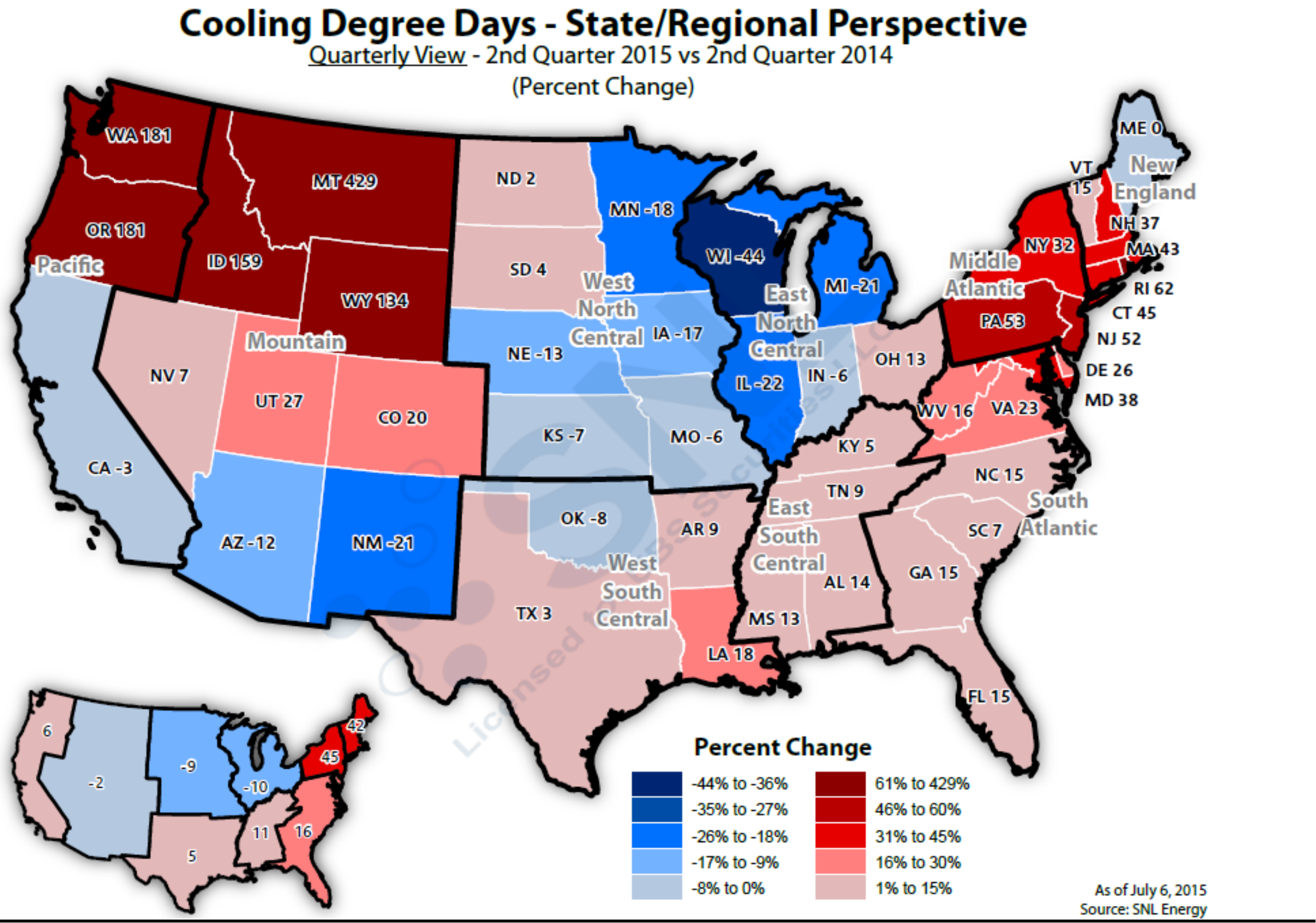
Risk to PJM remains load growth reduction

- **Did teams take advantage of the stock weakness?:** We would expect management teams to have accelerated repurchase activities as of late to capitalize on the slide in shares. In particular we look for confidence from companies that saw underperformance over the last three months with announced repurchase plans: Calpine (down 23%), NRG Energy (down 18%), and ITC Holdings (down 6%). Strong commentary and action could help to support shares

Weather pockets emerge: Wear your jacket or shorts?

We caution that the second quarter historically has the second lowest share of earnings (fourth quarter is the lowest and third quarter is the highest) and the impact of weather on usage is muted in comparison to the recent 1Q15 results. Overall cooling degree days (CDD) were 26% above normal and 9% higher than the comparable quarter but the impact was far from uniform. The entire East was warmer YoY with modest gains in the South and a larger jump in CDDs in the Mid Atlantic. While the Pacific Northwest saw significant increases, much of the Central saw cooler weather, the most pronounced impacts in Wisconsin and Michigan. Also of note is that Illinois, Indiana, and Ohio each set new records for June precipitation according to NOAA.

Figure 9: Quarterly Weather Map



Source: SNL Energy

More Positive 2Q Ideas

SRE: Management can point to significant execution wins in both Mexico and LNG, emphasizing further win potentials in Mexico for bigger projects as well as more confidence on execution of LNG deals through 1Q16.

EXC: See potential for reasonable quarter, nuclear retirements, and close of Pepco deal in ~August as all skewing substantially positive, particularly around any updated synergy guidance from deals (POM substantially under-earned ROEs).

More Cautious 2Q Ideas

SO: Discussion on balance sheet and cash flow issues from latest Kemper construction, regulatory, and partner pullout may skew significantly negative.

DUK: See continued negative commentary around Brazilian hydro, with the lack of expected improvement this year likely leading to downward guidance and estimate revisions.

DTE: We see potential disappointment around uncertainty on legislation. Beyond an inline quarter, we look for execution updates on midstream, and mgmt's view on latest iterations and timeline for MI comprehensive energy legislation.

TE: Further writedown of coal business could drive a weaker outcome; outcome could be positive.

ITC: A lack of details on Puerto Rico could cause investor concerns.

More Binary Outcomes:

WEC: Will 2016 EPS be ahead of its 5-7% or not given mgmt's guidance that it will earn its full ROE across all utilities including latest Integrys acquisitions.

ED: Will management disclose additional development on its retail strategic review? Details on the NTSB could also be included in the 10Q.

FE: Datapoint from PJM Transition Auction the day before the call could be telling.

Our Top Picks Overall

EIX, SRE, NEE: We continue to emphasize electric distribution growth as the primary source of capital investment in the industry over the next 5-10 years. This is in notable contrast to the waning importance of transmission system buildout in many areas of the country (New England not withstanding) as load growth continues to remain sluggish and the influence of distributed resources such as solar, wind, and electric storage gain an increasing foothold. Names exposed to this theme remain our top picks, including **EIX, SRE**, and potentially **NEE** (post-merger with Hawaiian Electric). We also note that the need for new transmission remains strong in New England as a result of persistent fuel delivery constraints and the presence of vast quantities of renewable-qualified, zero-carbon hydroelectric generation to the north in Canada. This may ultimately benefit ES, although there remains material uncertainty over regulatory and political approvals for their Northern Pass transmission and Access Northeast pipeline projects.

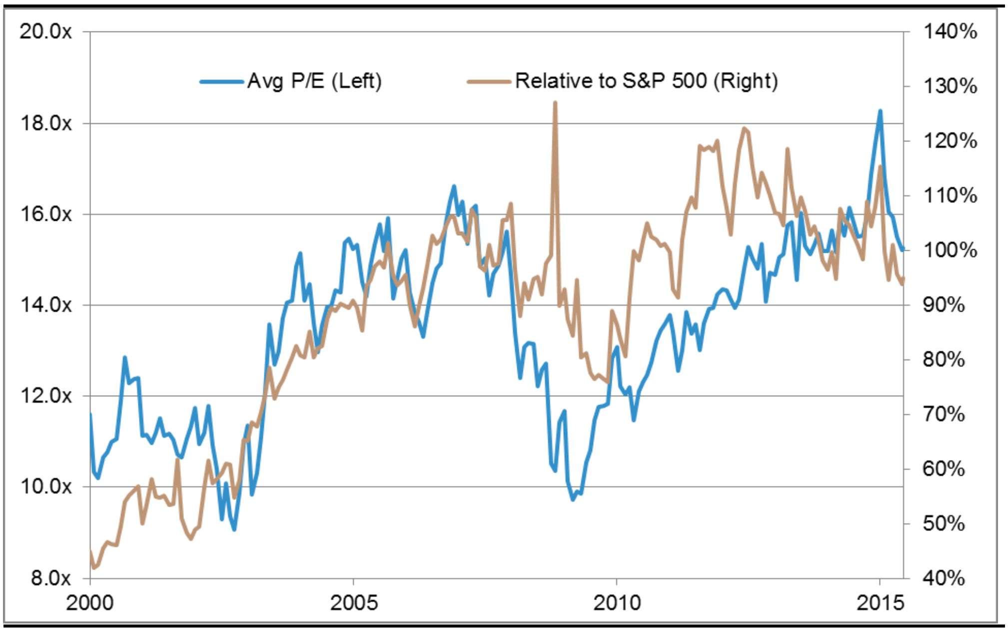
CMS, DTE: We also continue to emphasize Michigan (**CMS** and **DTE**) for its supportive and investor-friendly regulatory construct and potential for favorable legislation in the coming months. Bothe companies have the potential to invest and build up to 2 TWhs of new generation to solve capacity shortages in MISO Zone 7 as well as additional capex for environmental remediation under the EPA's forthcoming Clean Power Plan (CPP).

D, SRE: We also highlight **D** and **SRE** for their diverisified infrastructure focus, fast growing utilities, highly supportive state and regulatory regimes. **D** has also successfully spun out its Cove Point LNG import/export facility and other midstream assets into an incentivized MLP structure. SRE is considering a similar "Total Return Vehicle" MLP/Yieldco hybrid structure as well.

Valuations: Utilities now trading at a 5% discount

The utilities group is now trading at a modest discount to the S&P 500 (5%) versus a slight 2% premium in mid-April and an unsustainable 15% premium in January.

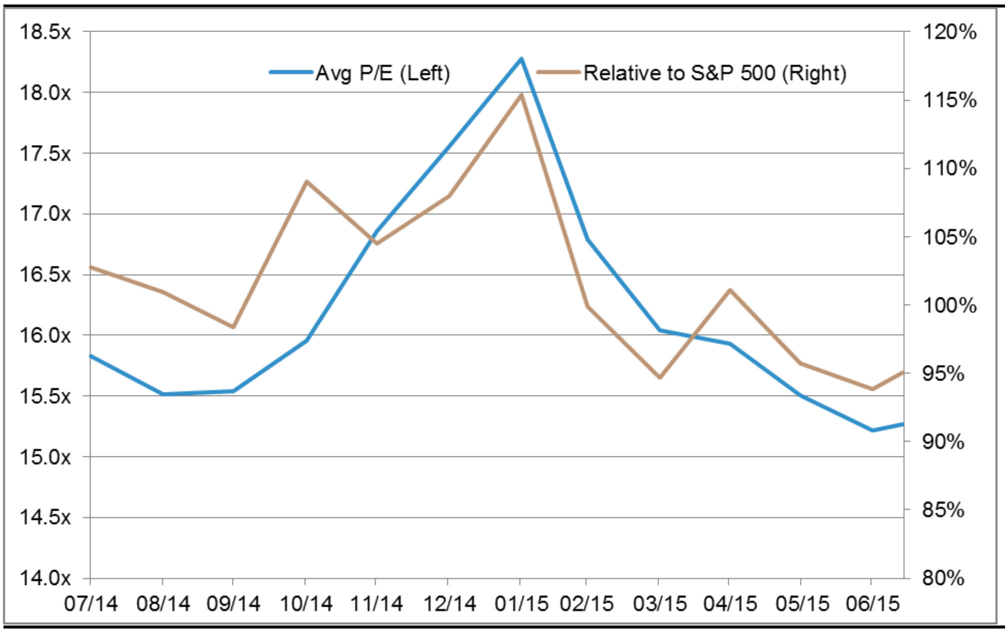
Figure 10: Utility vs S&P 500 Relative Performance



Source: FactSet and UBS Estimates

Utilities are now trading at their lowest relative valuation since February 2011 with the XLU declining 7% in 2Q15 versus flat performance for the S&P 500.

Figure 11: Utility vs S&P 500 Relative Performance – TTM

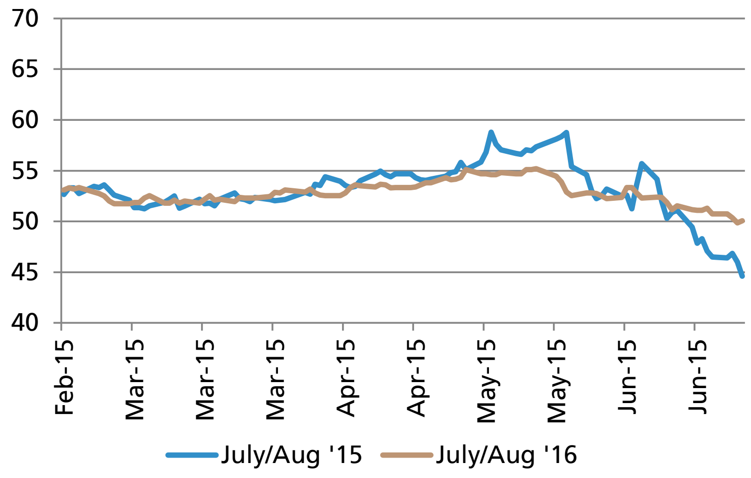


Source: FactSet and UBS Estimates

PJM: Addressing Summer Doldrums

Despite recent summer weather, PJM summer forwards following Texas downwards, weighing down power prices and share prices. We emphasize a disappointing summer was particularly likely following a run-up in recent year expectations for a particularly volatile summer given recent MATS-related coal plant retirements taking effect as of April, 2015.

Figure 12: Recent PJM Summer Forward Trends: 2015 expectations falling off

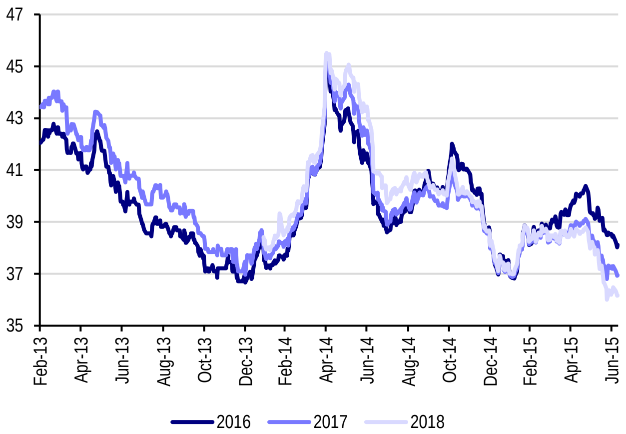


Source: Pkatts

What does this mean for annual PJM sparks?

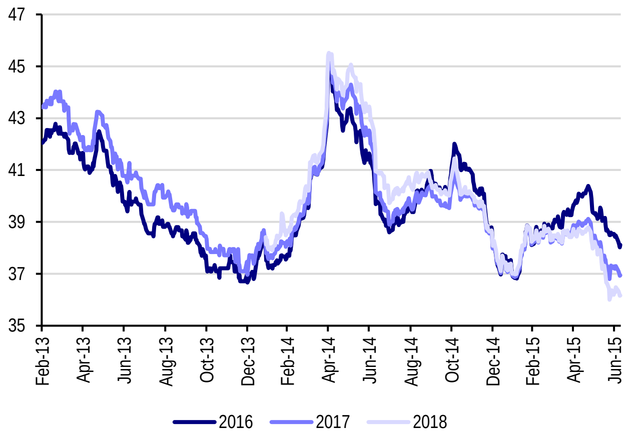
Forward sparks have started to fall off as well. We flag forward ATC power prices have reached multi-year lows once more too. In contrast, spark spreads are off multi-year highs only recently. We emphasize that weaker gas prices have been the primary driver of this weaker power price environment. The recent weakness in forward full-year sparks is primarily attributable to the shift downwards in PJM summer volatility expectations (shown above).

Figure 13: PJM Spark Spreads @ 7.2 HR ($/MWh)



Source: Platts and UBS estimates

Figure 14: PJM ATC Power Prices ($/MWh)



Source: Platts and UBS estimates

PJM Capacity: It's All About Transitions

We see PJM as possessing the greatest upside to expectations on account of the transition auctions, where industry executives appear to be more constructive on the price outlook than investors. Moreover, sentiment is relatively more neutrally skewed vs. the base auction. We suspect the base may well prove a sell the news event *aside* for those regions able to break out, specifically ComEd.

We see the transition auctions as the upside in the sector

Below we show the sensitivities for those generators where a $10/MW-Day change in PJM capacity prices relates to a ~1%+ increase in EPS or EBITDA.

Figure 15: PJM Capacity Market Sensitivities

PJM Capacity Market Upside	PPL (Talen)	DYN	NRG	EXC	FE	PSEG
Nameplate Capacity (MW)	12,783	11,940	18,658	22,142	9,477	12,042
EFORd Adj. (MW)	12,052	11,265	17,506	20,794	8,942	11,333
Clearing Price in 2016/17 $/MW-Day	$ 59.37	$ 59.37	$ 59.37	$ 59.37	$ 59.37	$ 59.37
Clearing Price in 2017/18 $/MW-Day	$ 120	$ 120	$ 120	$ 120	$ 120	$ 120
$10/MW-day Sensitivity ($M)	**44**	**41**	**64**	**76**	**33**	**41**
Impact to EPS				**$ 0.06**	**$ 0.05**	**$ 0.05**
2017 EPS or EBITDA	**$ 633**	**$ 1269**	**$ 2941**	**$ 2.60**	**$ 2.22**	**$ 2.83**
% of total 2017 UBS Estimate	**7.0%**	**3.2%**	**2.2%**	**2.2%**	**2.3%**	**1.9%**

Source: SNL, PJM, and UBS Estimates

PJM Likely to Moderate in 2019/2020

Looking through the near-term upside in capacity prices, we suspect prices to come back down in the next year on account of the following:

- **Lower demand risk:** PJM stakeholder process is reviewing potentially meaningfully negative revisions YoY
- **Continued new entry:** With gas prices modest and capacity prices relatively high, we suspect new entry will remain plentiful.

Are we seeing the topping out now?

Despite optimism on capacity prices, energy markets have continued declines

We see the risk to all of the power markets is the cheap price of natural gas – which continues to not just pressure power prices, but also acts as an enabler for new gas plant entry into the capacity auctions. We suspect gas prices are likely bottoming out of late, as we see further spot pressure on Henry for any sustainable period as untenable given the switching implications.

<u>Broadly, we see heat rates and spark spreads as more 'topping out' than gas.</u>

PJM: We suspect new entry in PJM beginning in 2016 will continue to drive meaningful backwardation in the market.

CAISO: In California, we see limited improvement opportunity as renewables continue to be developed at a meaningful pace for the foreseeable future

ERCOT: While bearish overall, we see a low as coming sooner than many other markets, potentially in ~2016/17.

ISO-NE: As for New England, we see pressure as longer-dated with renewable acceleration and Canadian imports likely longer-dated into the ~early 2020's vs. other markets. Declining gas basis as pipes are developed should hurt baseload operators disproportionately. Overall, we see this market as intact for sparks, if not a bit bullish.

MISO: Last, we see a wider negative trend on prices with expanding gas deliverability putting a slow steady pressure on power. We see MISO heat rates as potentially expanding, amidst this gas basis pressure.

NYISO: We see capacity as remaining elevated and stable, but a wider pressure on downstate gas will put downward pressure on power prices. Moreover, the first new merchant entry in downstate could further question value. This market could be an interesting long-term recovery story amidst real potential for several nuclear retirements.

Alberta: Less of our focus, but here too, we see many new and potential entrants from any sustained recovery, despite wider oil headwinds.

Texas: When Will it Have the Limelight Again?

In contrast to other markets where power prices continue to trend lower, spark spreads continue to trend meaningfully lower across this market as summer power price expectations have once more failed to materialize.

What's coming up?

- **Another summer without volatility:** With rain in June putting downward expectations on power prices and load for yet another summer, we flag little by way of volatility has helped keep a lid on expectations in ERCOT. We flag 2015 also has continued meaningful new capacity additions, as well as benefits in 1H from new investments in plant put into service only last summer. Moreover, with wind projects typically targeted for in-service late in the year, meaningful step-up in wind as part of the latest PTC extension has its first real impact this year.

- **More solar?** We expect to see not just more wind, but specifically more solar to be announced in the ERCOT market. Notably, Austin Energy appears poised to solicit 600MWs of further solar at $38/MWh to achieve its 55% RPS target, as part of a source of replacement capacity for retiring gas.

- **Reforms at ERCOT too?** With weather and prices proving exceptionally mild, another key angle remains whether further reforms to the ORDC curves and other tools to drive scarcity could yet be reviewed again.

When will this market bottom?

We see the Texas (ERCOT) market as likely bottoming in the ~2016 timeframe, as this reflects peak new build of new gas, wind, and solar. We don't see any credibility to further new supply completing or entering the market if it doesn't already have a credible backer. The existing backlog would appear to exhaust all such new entry by 2017, suggesting 2016 may well prove the 'bottom'.

- **What's the risk? PTC and ITC extensions.** Among the biggest potential risks to the ERCOT market remains the potential for a further extension in the Production Tax Credits (PTCs) and Investment Tax Credits (ITCs) for wind and solar respectively. We see wind as being a credible 'merchant' investment even into weak off-peak prices (albeit in the low-to-mid 20's, pricing is certainly as 'tight' as it can possible get). Should there be no extension, there would be a stark 'shut off' of new renewables into the ERCOT market at year end 2016.

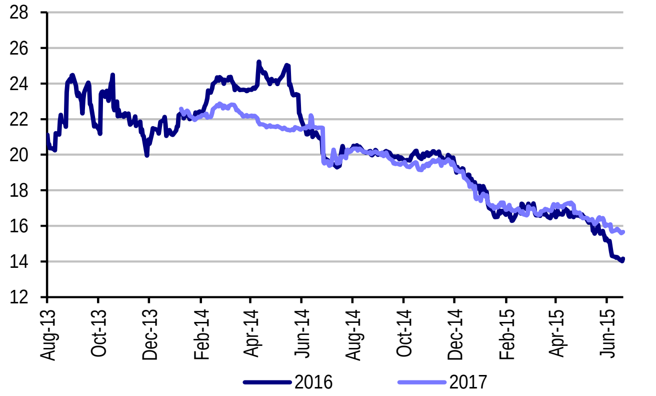
  When could an extension happen? A further extension of the PTCs could very well be part of a further tax extenders bill as soon as this year end, however, more likely will be part of a very late 2016 lame-duck session tax extenders bill. We see a further extension of the PTC as *likely*, however, see a real potential for a *reduction* in the level of compensation (potentially phased downwards as part of a multi-year deal). This would at least alleviate pressures on continued new build in Texas. We suspect this debate to gain greater attention

- **Will all this generation move forward? Exelon continues to move.** In hindsight, we see the top of the ERCOT market as being when Exelon, a meaningful incumbent, opted to pursue two new CCGTs at the same time in the market, predicated on an attractive ~$700/kW greenfield build cost from GE as part of installation of its latest H-Series turbine. We suspect others

pursuing projects, albeit without financing will prove unable to move forward given the substantial pullback in commodity price.

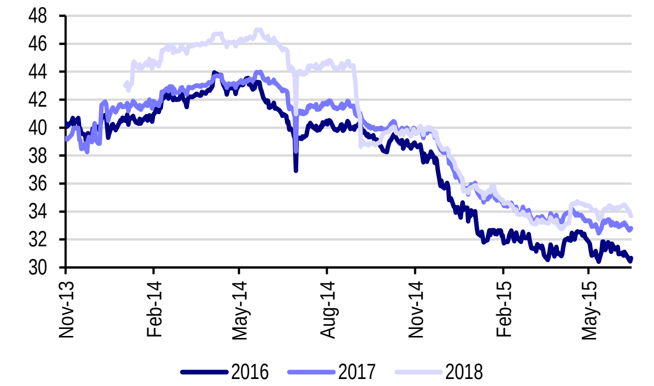
- **A glimmer of hope? Seeing some contango re-emerge in forwards:** Consistent with our expectations for sparks to bottom in 2016, we flag that 2017 improvements have re-emerged relative to 2016 only in recent months, avoiding the sharpest of the recent slide.

Figure 16: ERCOT Houston Spark Spreads @ 7.2 HR ($/MWh)



Source: Platts and UBS estimates

Figure 17: ERCOT Houston ATC Power Prices ($/MWh)



Source: Platts and UBS estimates

Midwest Power: Nuclear Recovery?

Prices have proven a tad more resilient across this market, however, gas prices continue to drive the outlook with prices revisiting lows last seen in January 2014 and 2015 respectively across all forward years.

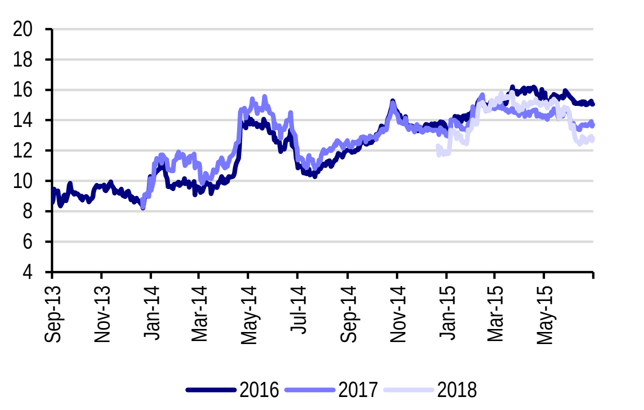
- **Are we at new entrant levels? Not quite yet in our view.** We see sparks as still sufficiently unattractive to limit new entry, but caution should capacity prices spike, we do increasingly see some risk. For now, the entrant risk remains primarily oriented towards the Ohio market, but could well see developers such as Invenergy poised to jump on the opportunity around future coal and nuclear plant retirements in the NI Hub market.

- **Nuclear retirements, finally?** We suspect we are close to seeing Exelon pull the trigger on plant retirements. We look for this to occur in the September timeframe. That said any decision *won't* be final until late 2015, at which point in time the company will not have latitude to re-order the core refuelling in time for its next fuel cycling. Ordering late in the year would likely enable a smaller core fuel loading. We see the timing of its first unit coming offline in 2016, with the second in 2017 should it move forward.

  Timing around refuelling dictates timing of nuclear retirements

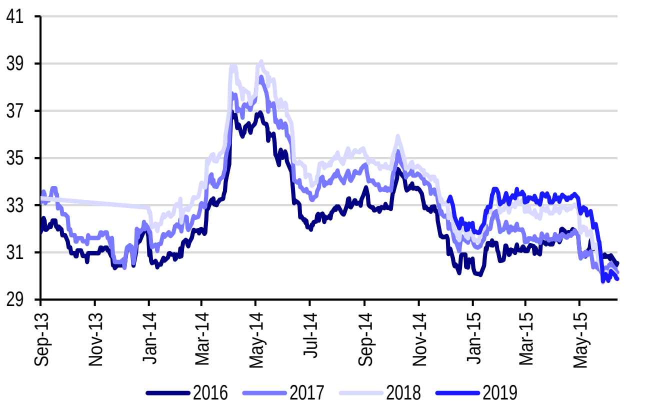
  Some credibility on the line – something must change. We see management as poised to make critical decisions on the future of its portfolio, beyond just Quad Cities in coming months. We suspect a decision on what to do with Clinton may also hang in the balance around any eventual Illinois legislation for energy recovery. The biggest near-term driver for NI Hub and Indy Hub power prices remains whether nuclear plants are retired this fall.

Figure 18: NI Hub Spark Spreads @ 7.2 HR ($/MWh)



Source: Platts and UBS estimates

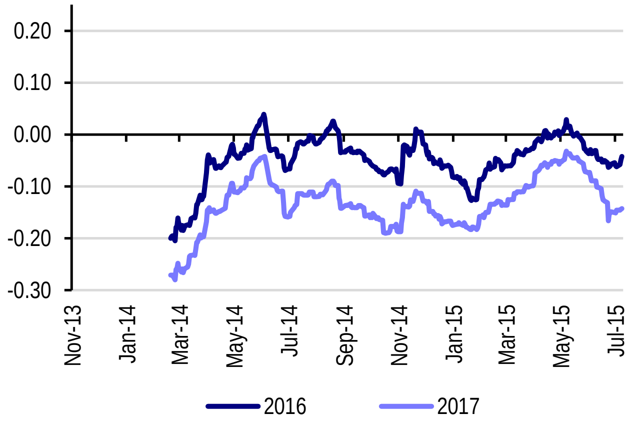
Figure 19: NI Hub ATC Power Prices ($/MWh)



Source: Platts and UBS estimates

- **PTC extension a risk here too:** Although less obvious, we see a further extension of the PTC credits for wind as a further headwind, given continued development of renewables. This is less negative than for the ERCOT market.
- **What does gas basis do for Chicago?** We continue to perceive risks around a further potential decline in regional gas basis as new pipes reach in-service and are expanded, such as REX. This remains the chief longer-term focus around any turnaround in the Midwest market. Basis has remained relatively stable through the last year at roughly a dime discount to Henry Hub.

Figure 20: Chicago Citygate basis ($/MMBtu)

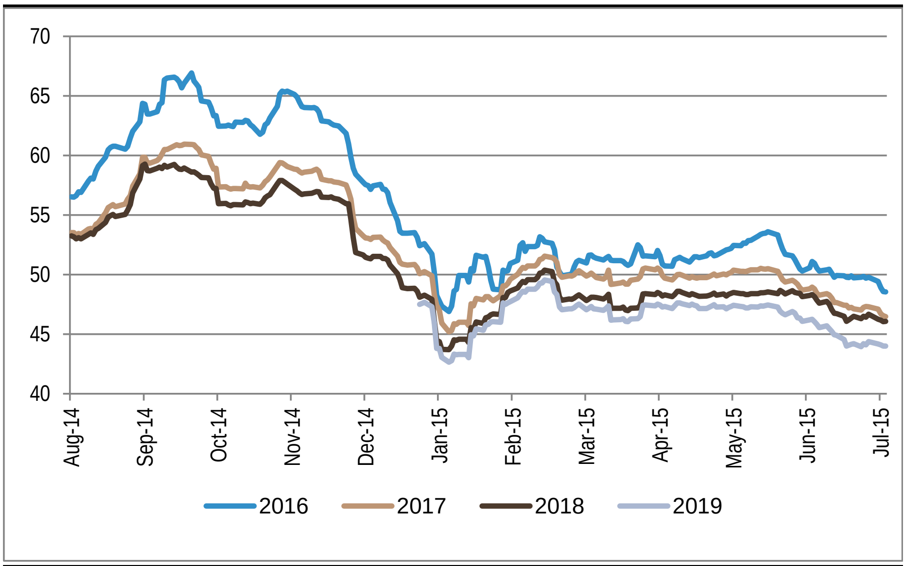


Source: Platts and UBS estimates

New England: Poised to Collapse?

New England power prices have seen the largest dollar declines given the pressures of risk premiums embedded from a repeat of polar vortex conditions and lower oil prices, which was setting the highest prices for the Jan/Feb curve earlier. We see this market as continuing to see pressure as gas procurement efforts gain momentum in ~2017. We see transmission import and renewable threats as only exacerbated by recent efforts to upsize procurement efforts.

Figure 21: Mass Hub ATC Pricing ($/MWh) – hurts baseload generators



Source: Platts

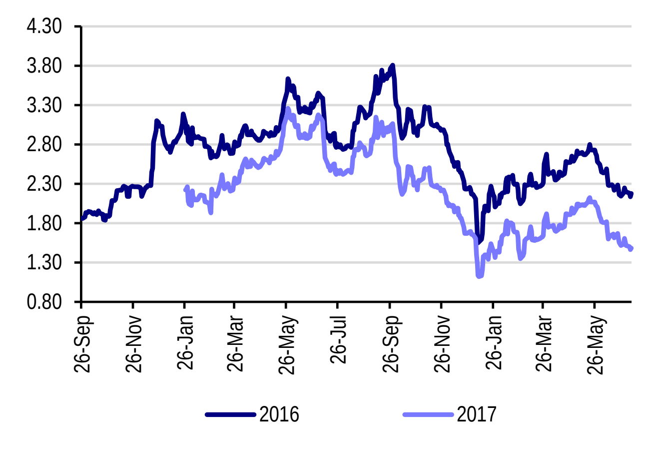
Real Risk Here is Structurally Declining Gas Prices

We see a very real potential for new gas to finally make its way back into this market. Specifically, we see credible efforts to both expand existing assets (Algonquin) as well as build new (Kinder's Access Northeast through MA). While approval for less traditional electric utility procurement is not our base case, we see this as yet a further risk.

We see a long-term trend, albeit with significant upside tail-risk in the interim

Prices will continue to trade with a premium, reflecting potential for further scarcity events

Figure 22: Algonquin Gas Basis ($/MMBtu)



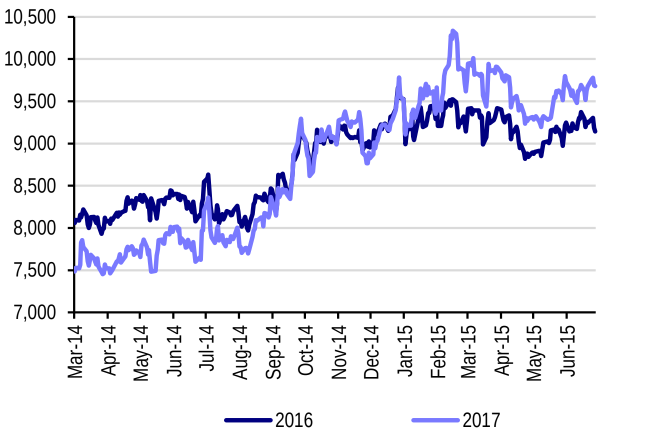
Source: Platts

Baseload assets here will face structural headwinds. We see primarily ETR, but also D and NEE as seeing the most structural headwinds from their respective nuclear positions in this market. Seeing pressures forthcoming, the question remains *if and how* D and NEE could exit their unclear positions? Given the FCF from the units today and limited buyers of nuclear plants, we suspect they will both wait for these units to generate relatively limited EPS prior to divesting. We see this entire market as primarily in 'cash harvesting mode' in the interim for the parent companies.

Spark Spreads: Some upside? We think in Medium Term

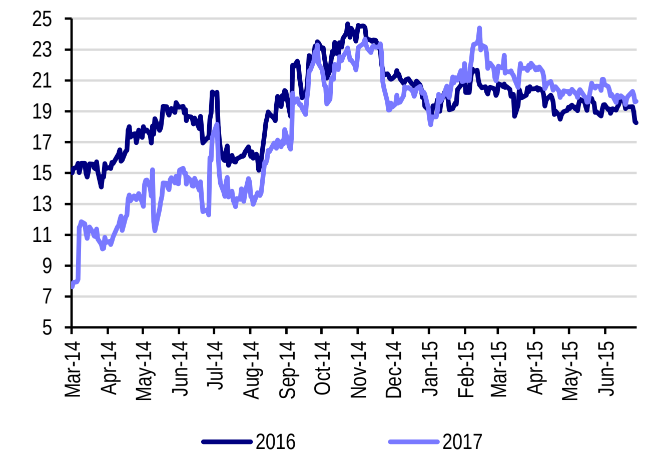
- We think cheaper gas coming into New England could be resilient for *some generators in the region*.
- We suspect those generators in Southeast CT will be the most advantaged to the cheap gas – whereas plants 'at the end of the line' in Northern New England will *remain* disadvantaged.
- The goal remains to send cheaper gas up New England, eventually providing the Eastern maritimes with cheaper natural gas when flows permit.
- The question is how to frame *gas on gas* competition amidst lower gas prices. We see this benefit as potentially accruing to DYN's recently acquired New England gas CCGT portfolio.

Figure 23: Mass Hub Heat Rates (btu/KWh)



Source: Platts

Figure 24: Mass Hub Spark Spreads @ 7.2



Source: Platts

New Rules for the Next Capacity Auction

On June 30th, FERC accepted ISO-NE's petition for a number of changes to the market structure. Docket ER15-1650.

- **Pushing up the 'dynamic' de-list bid:** FERC recently approved a further increase in the dynamic de-list price to $5.50/kW-mo ($180/MW-day), up from $3.94/kW-mo previously ($130/MW-day). This change is likely to provide an increased 'floor' price to capacity prices, as we suspect most generators would opt to not participate in the auction at these levels; loosely interpreted, we see the dynamic delist bid as roughly equivalent as the bid-cap with which units can opt out of the auction without being needed to permanently retracting from future participation. We maintain our more constructive view on this market.

- **Applying new rules to imports of capacity:** Following up on some of the concerns raised from the last several FCA auctions, FERC instituted a series of new rules around how transmission imports into ISO-NE will be treated. While opaque

- **What about buy-side mitigation for new transmission too?** While the threat of new transmission build would clearly put downward pressure on regional energy and spark spreads, we are gaining greater confidence that ISO-NE is likely to mitigate any large-scale hydro efforts from adjacent regions, particularly if from discrete DC interties with specific generation behind it.

- **Regional zones worth greater attention:** We emphasize a further wildcard in the next FCA remains how regions will be defined; notably, any prospects for new transmission imports such as ES' Northern Pass could yet be relegated to their own (lower-priced) region in New Hampshire. *Bottom line, don't expect any regions to break out separately again this year.*

So where do we think capacity prices are headed?

Following their peak at $9.57/kW-mo in the latest auction, we maintain our $6.00/kW-mo formal estimate into the next auction. We see the latest move to firm prices up at $5.50/kW-mo as only lending support to our price estimate. We flag that many in this market remain more bullish, with some anticipating similar prices to last year (YoY), albeit we see this as doubtful, particularly with increased scrutiny and new rules around import capacity.

We see $5.50/kW-mo or $180/MW-day as the floor price in this market

What about the spark spread outlook

- Further new assets remain contemplated: We understand there are multiple new greenfield and brownfield expansions that continue to evaluate a bid into the next FCA auction. We suspect prices will substantially moderate in the next auction as new auction cleared in the last auction is 'absorbed' (recall that ISO-NE is a relatively small market making any additions rather 'chunky')

- In the long-term, high new entry costs will support above long-term trends Despite the robust capacity payments, we suspect spark spreads will remain elevated as new entrant prices for units are meaningfully higher in this region at $1,200-1,500/kW vs. $1,000-1,100/kW seen in PJM.

More New England Reading:

2/5/15 Reaching the Summit in New England [Summary of latest auction results]

2/2/15 How Good Could New England Really Be?

11/17/14 Upping the Stakes in New England

10/20/14 Solving the Supply Deficit in New England

8/19/14 Adding Gas, or Moving it the Right Way?

9/17/14 Can A Gas Gambit Break The Northeast Bottleneck?

9/23/14 Importing New England's Gas Deficiency

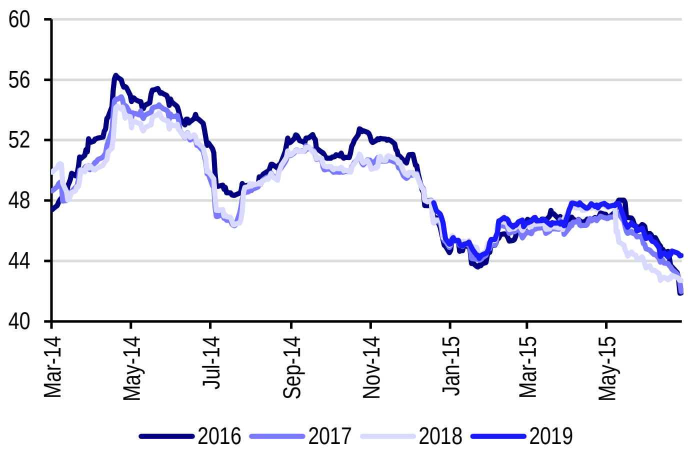
9/15/14 Burning the Midnight Oil as Clock Counts Down on New England's Adequacy

New York: Downstate Market (Zone-G)

Zone G has traded sharply lower with the 2015 forwards moving far more dramatically than in PJM. We sense the recovery in regional power prices reflects declining expectations. While near-term expectations may well be alleviated by concerns around whether the Bowline plant is coming back, the wider recovery in prices is clearly attributable to a bounce in gas basis expectations.

We see confirmation for CPV to move forward on its Valley plant as likely putting backwardation in the forward curve. We have yet to see this materialize and remain more widely concerned.

Figure 25: New York Zone-G ATC Pricing ($/MWh)

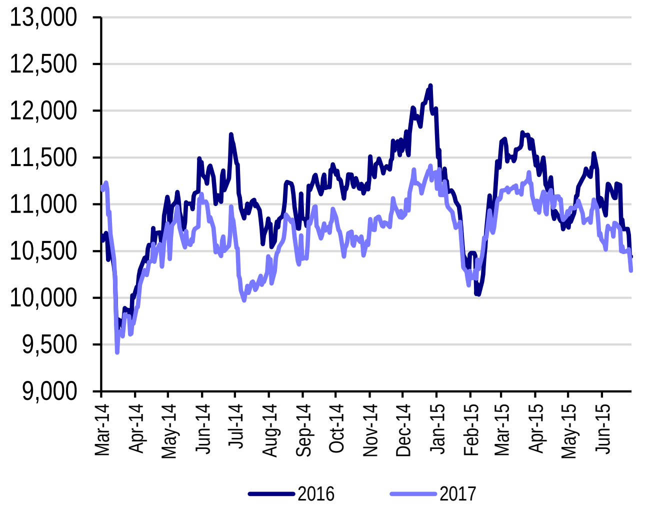


Source: Platts

Focus is on Gas Basis Expectations

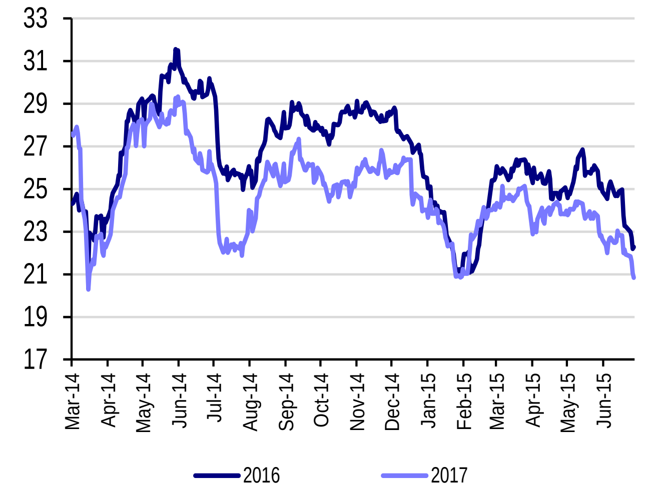
We attribute the recent slide and recovery to expectations on gas basis improvement with Transco. Notably, breakthoughs appear to have been made on construction of the Constitution pipeline into the Zone G region. Additionally, new plants have continued to indicate their desire to re-enter the market, with both Danskammer indicating a full comeback, as well as NRG pursuing repairs on its Bowline unit to bring the unit back to full operational capability.

Figure 26: New York Zone-G Heat Rates (btu/KWh)



Source: Platts

Figure 27: New York Zone-G Spark Spreads @ 7.2 using Transco Z6 Gas



Source: Platts

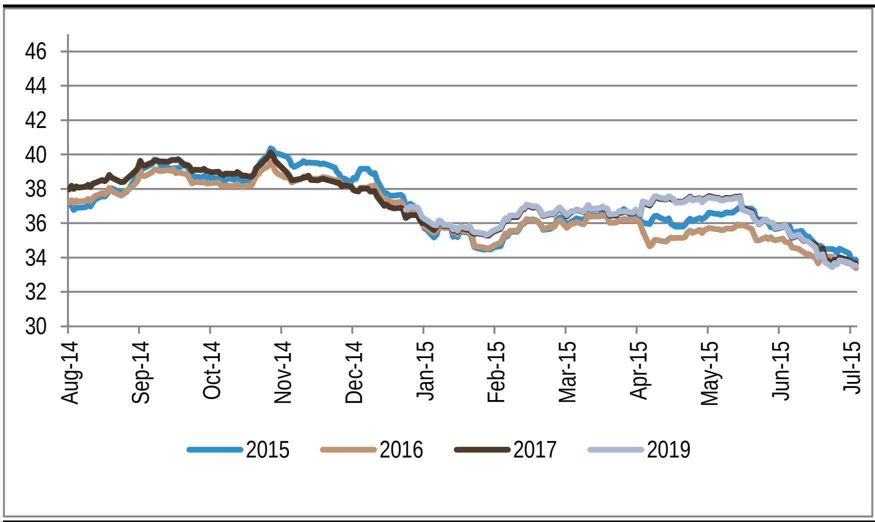
New York Upstate (Zone A) Market

Falling below previous lows

Turning to New York, in Zone-A, prices continue to remains near 1Q lows. We emphasize that while long-term nuclear retirements remain a potential upside, it's certainly not a near-term upside to reflect into estimates. We suspect pressure on prices is likely due to continued pressures from shale gas on regional power.

We see recent legislative as firming up expectations for Zone A to recover as potentially enabling a palatable retirement plan for several of upstate NY's coal plants; notably this would include Cayuga.

Figure 28: New York Zone-A ATC Pricing ($/MWh)



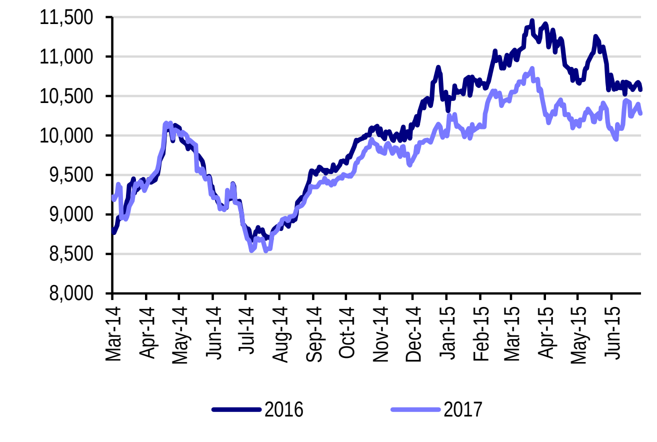
Source: Platts

Power down, but sparks aren't using regional 6 prices

While nominal power prices have round-tripped back to levels at the start of the year, heat rates are substantially higher. We continue to see an argument for medium term degradation as new units are brought back into the market. We also do not expect Ginna to retire through the medium term (a deal with Exelon and RG&E is expected in coming weeks around exact contract details); we suspect an effort for long-term 'Clean' Energy Standard could yet be pursued by Exelon to keep the unit around as well. Spark spreads have proven intact.

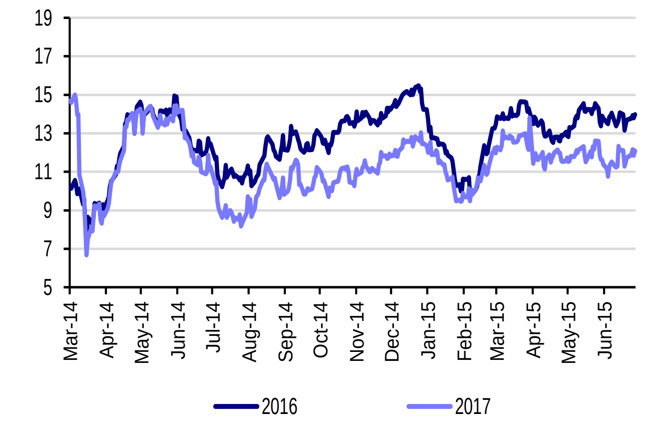
Sparks are intact using either Transco Zn 6 or Dominion-South

Figure 29: New York Zone-A Heat Rates (btu/KWh)



Source: Platts

Figure 30: New York Zone-A Spark Spreads @ 7.2 ($/MWh)



Source: Platts

<u>Recent reports on New York:</u>

New York Prices Prove Resilient 4/6/15

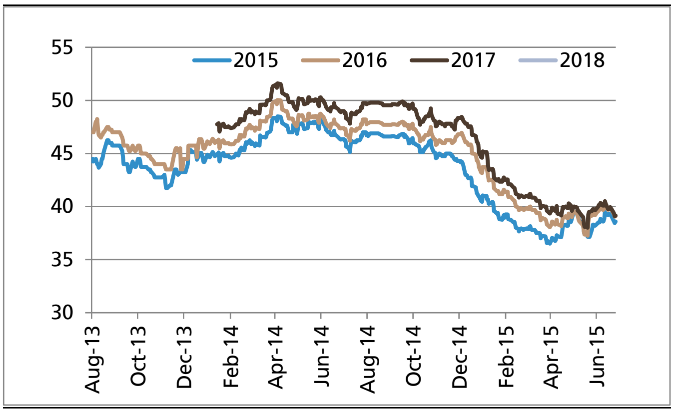
Turning New York Upside Down 3/26/15

California Commodity Views

Fundamentally, we continue to see meaningful long-term pressures on California forwards as the drought normalizes in future years. The charts below show evolution of on-peak and off-peak power prices for the NP15 market. Both curves have seen meaningful degradation this year. We continue to believe that power prices remain fundamentally pressured from continued renewables growth; despite offsets from the drought.

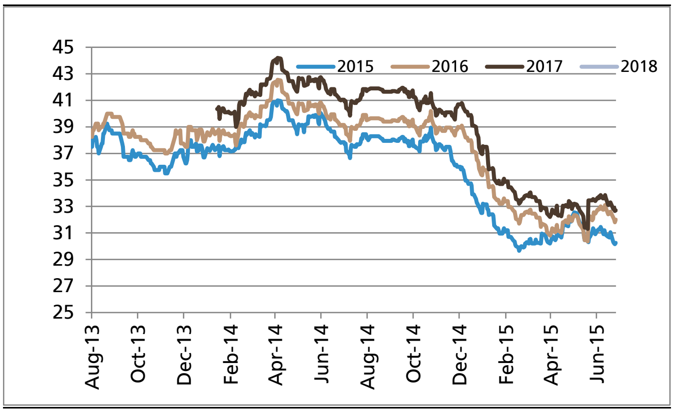
Low hydrology cannot hold the market up for too long…

Figure 31: On-Peak NP15 Prices ($/MWh)



Source: Platts

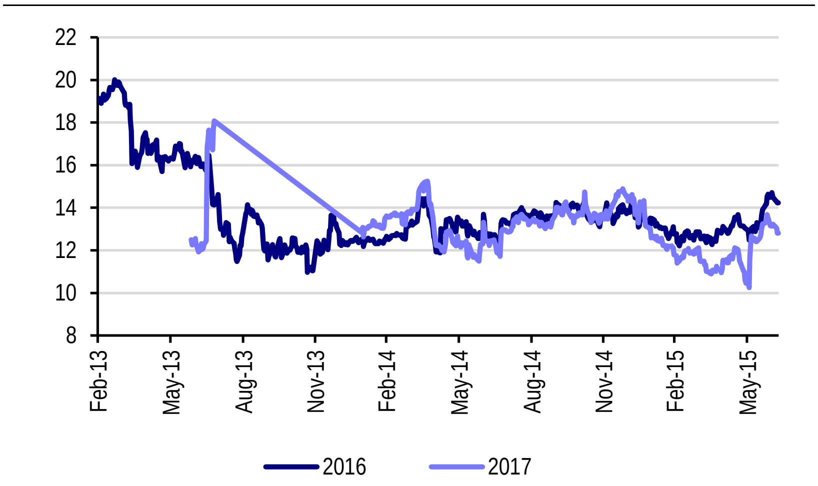
Figure 32: Off-Peak N15 Prices ($/MWh)



Source: Platts

Normalization of hydro conditions shows backwardation. Spark spreads have only recently begun to reflect the expected backwardation in forwards as hydro conditions normalize YoY, and reflect continued growth in renewables (squeezing margins). We expect further structural pressure on long-dated power forwards with the RPS poised to expand to 50%. We suspect worsening drought conditions have allowed for sparks to remain largely intact through the last 18-month period. *We see gas consumption from CCGTs as likely reaching records this year amidst the drought.*

Figure 33: NP15-PG&E Citygate Spark Spread @ 7.2 Heat Rate ($/MWh)



Source: Platts and UBS estimates; *not* adjusted for CO_2

Have we seen the worst?

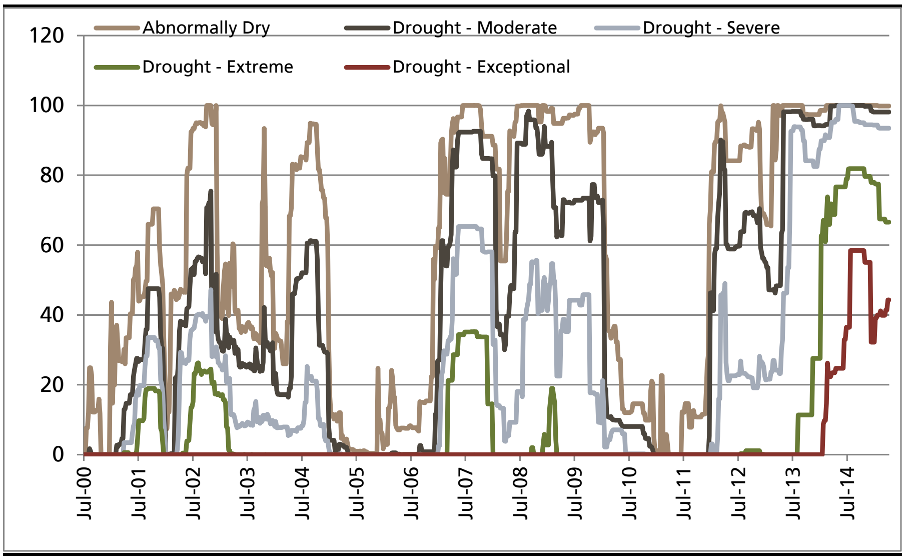
California Drought: Alive and Kicking

The most recent anecdotal data point illustrating was a bill signed by Gov. Jerry Brown two days ago which bans cities and counties from imposing fines for

violations of "lawn maintenance" ordinances. Latest data from the US Drought Monitor shows that 94.59% of CA land area is under "Severe Drought" conditions, compared to 94.34% at the start of the year; 46.73% of area is under "Exceptional Drought" conditions vs 32.21% at the start of the year. The area under "Extreme Drought" conditions however is now 71.08%, vs 77.94% at the start of the year.

If the drought is taken out of the equation, we are overall increasingly bearish on the outlook for the California power market amidst accelerating renewables – solar in particular – penetration in the state. However, to provide context, we include California drought data since 2000, illustrating the severity is actually worse than that triggering the last power crisis in the state, when it was sizably more dependent on hydro power.

Figure 7: California drought data (2000-present; % land area): Coming off *extreme*?



Source: NOAA

Looking at the future of California: Putting 50% RPS back on the map

Following a quiet period of any further RPS increase, we see the latest talk of increasing the RPS to 50% by 2030 as potentially kick-starting stalled utility-scale procurement efforts. We still see distributed generation efforts as putting downward pressure on power prices throughout the forecast period, as even once tiers are addressed – and ITC steps-down – we suspect penetration will continue.

- **Will renewables focus be eclipsed by focus on transportation:** As the state attempts to hit it's carbon targets, and increasingly meshes this view into its RPS targets, we suspect utility-scale procurement may take a backseat to efforts to continue to encourage DG and reductions in GHGs from the transportation.

- **What will this do to the REC market?** We are increasingly focused on the outlook for incumbent contracts in California as those PPAs eventually roll off. We specifically look towards CPN's Geyser portfolio and its current implied price closer to ~$20/MWh, vs the current market price in the $10-15/MWh. *A change in RPS could drive resilience in prices.*

  For more on the REC market outlook please see our latest note.

Gas Prices: Are we finding a low?

Our latest 2015 coal-to-gas switching prognosis

With MATS environmentally-driven coal plant retirements now fully baked in as of the April 15th deadline, we've seen further declines for 2015 (forward) gas pricing at TETCO M3, Transco Zone 6, and Dominion South Pt since our March update. Transco Zone-6 (non-NY) has also broken down noticeably as well, a major supply point for PJM. These zones remain far below the historical spot for 2012, which was the last period of substantial coal-to-gas switching.

The question is how much worse can gas yet? Not so much in our view.

Our read of YTD power and gas basis movements:

- **Winter came late:** supported earlier this year by late winter weather. This propped up gas prices, and limited coal switching earlier in the winter.

  Marcellus: Continues to push down regional prices to new absolute lows, notably lower than levels seen in 2012.

Figure 34: Comparison of 2008-2014 Average Daily Natural Gas Prices to the latest 2015 Forward Swap (7/10/15)

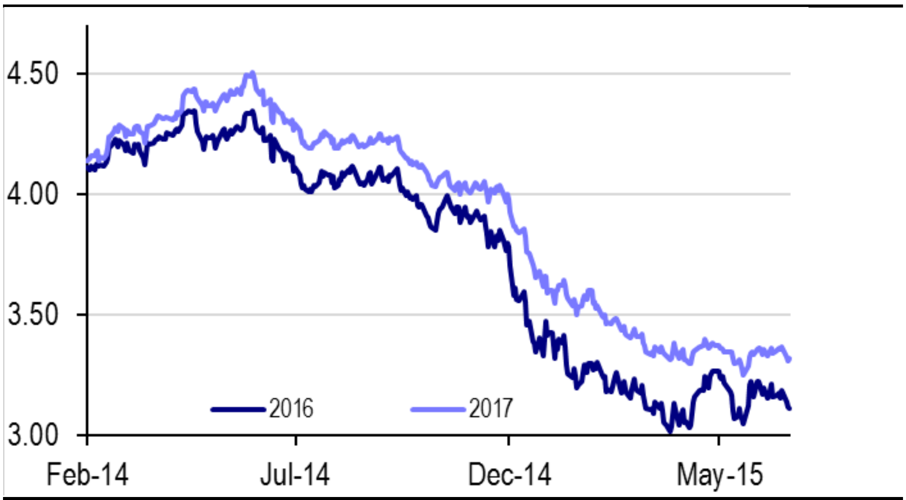
	Henry Hub Spot	Leidy Hub Natural Gas Spot Px	Algonquin City Gates	Tetco M3	Transco Zone 6 NY	Transco Z6 non-NY	Chicago City Gate	Houston Ship Chnl	Dominion South Pt	SOCAL CITY GATE SPOT PRICE	PG&E City Gate	RUBY MALIN WEST COAST
2015 FY Fwd Swap	2.88		4.36	1.92	2.79	2.40	2.92	2.84	1.49	3.13	3.25	2.82
2015 Spot YTD	2.79	1.39	6.65	3.47	5.36	5.23	2.99	2.73	1.68	2.84	3.06	4.71
2014	4.32	2.74	8.15	5.03	6.39	6.44	5.61	4.30	3.25	4.71	4.85	4.67
2013	3.72	3.07	6.97	3.93	5.07	4.08	3.86	3.70	3.51	3.95	3.97	3.58
2012	2.75	2.83	3.97	2.98	3.27	2.99	2.85	2.71	2.77	3.02	3.11	2.89
2011	3.98	4.33	5.01	4.61	5.01	4.68	4.12	3.93	4.11	4.09	4.23	
2010	4.37	4.89	5.28	5.10	5.39	5.25	4.45	4.33	4.57	4.27	4.53	
2009	3.92	5.00	4.80	4.63	4.89	4.64	3.93	3.75	4.23	3.67	4.12	
2008	8.84		10.06	9.82	10.12	9.82	8.79	8.48	9.28	4.86	8.58	
2015 FY Fwd Swap vs 2012	0.13	(2.83)	0.39	(1.07)	(0.48)	(0.59)	0.08	0.13	(1.28)	0.11	0.14	(0.07)
2015 FY Fwd Swap vs 2012	5%	-100%	10%	-36%	-15%	-20%	3%	5%	-46%	4%	4%	-2%
Previous results (June 2015)												
2015 FY Fwd Swap vs 2012	*0.17*	*(2.83)*	*0.13*	*(1.03)*	*(0.44)*	*(0.53)*	*0.09*	*0.17*	*(1.19)*	*0.14*	*0.14*	*(0.02)*
2015 FY Fwd Swap vs 2012	*6%*	*-100%*	*3%*	*-34%*	*-13%*	*-18%*	*3%*	*6%*	*-43%*	*5%*	*5%*	*-1%*
Previous results (March 2015)												
2015 FY Fwd Swap vs 2012	*0.11*		*0.02*	*(0.91)*	*(0.42)*	*(0.30)*	*(0.01)*	*0.10*	*(1.02)*	*(0.03)*	*0.04*	*(0.22)*
2015 FY Fwd Swap vs 2012	*4%*		*0%*	*-31%*	*-13%*	*-10%*	*0%*	*4%*	*-37%*	*-1%*	*1%*	*-8%*

Source: Bloomberg

We may be finding a low, but where is the recovery?

Forward gas prices have proven to be more resilient of late, in contrast to power price trends. We see certainty in a trend for Henry Hub prices as indicative of a potential bottoming of expectations. That said, with 2015 Henry Hub having bottomed in the mid $2.60/MMBtu on a spot month basis – and still trade sub-$3, the question is whether 2016 and 2017 will converge down to these levels as we roll forward.

Figure 6: Henry Hub Gas Price ($/mmBTU

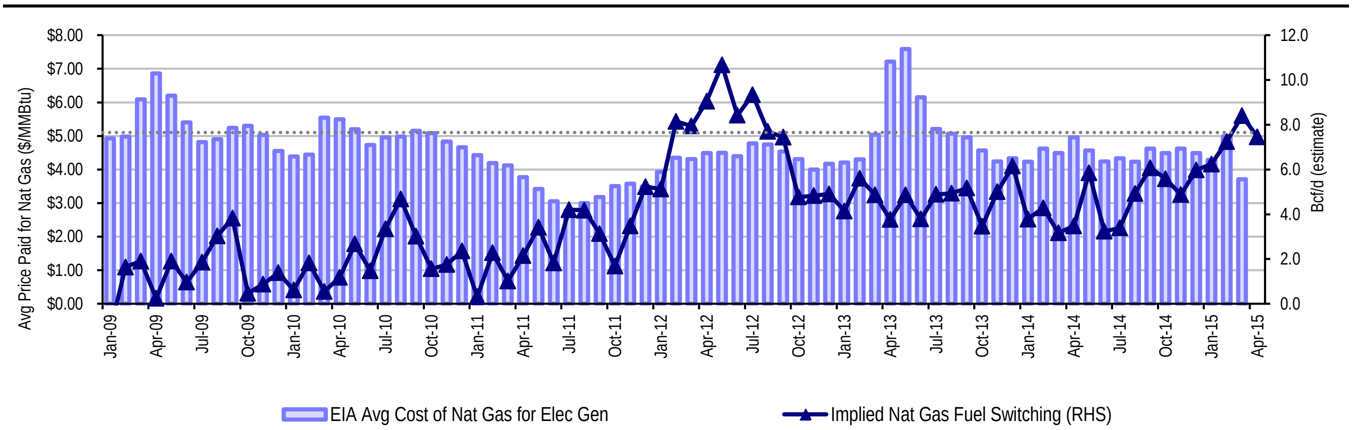


Source: FactSet

Coal to Gas Switching Reaching a New Peak?

Gas generation over the first four months of 2015 averaged ~24 bcf/d. Our expectation is for gas generation to average ~26 bcf/d in 2015, with potential for a disproportionate uptick from retirements mandated in April 2015 for MATS, as well as substantially cheaper mid-Atlantic gas; ~+3 bcf/d YoY is achievable.

Figure 35: Coal to Gas Switching (relative to 2008) (Bcf/d) vs Avg cost of Natural Gas ($/MMBtu) for Elec Generation



Source: EIA and UBS estimates

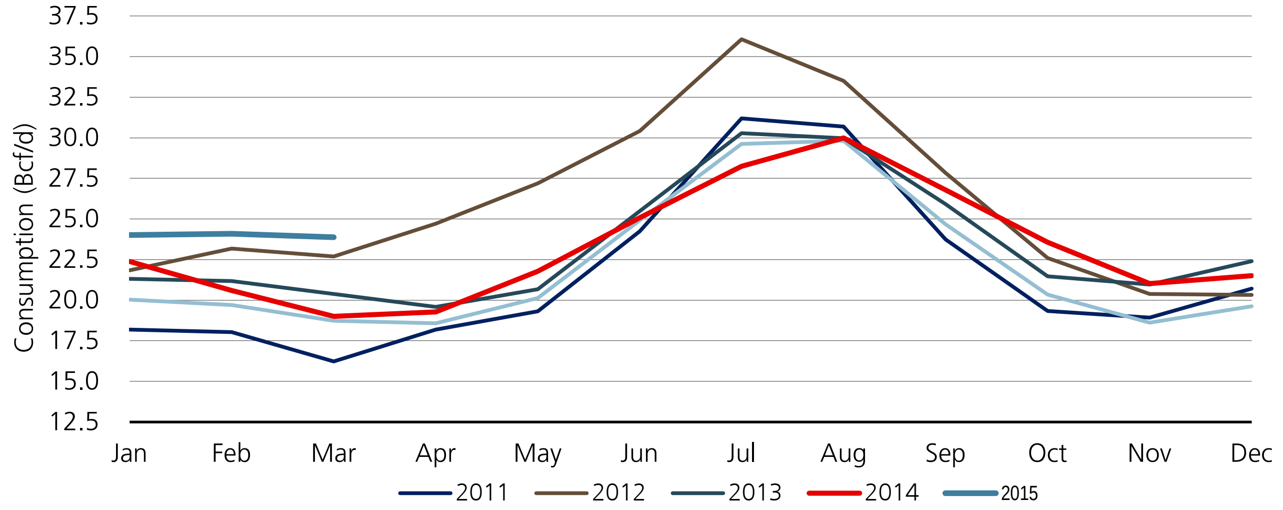
Figure 36: Gas Burn (bcf/d) in the Generation Stack – How do recent years compare?

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2007	14.8	17.1	15.7	16.5	22.0	26.8	25.4	19.9	18.8	15.3	16.4	16.3	18.8
2008	17.9	15.8	15.5	16.2	16.0	22.7	26.0	25.4	20.6	18.2	15.8	15.9	18.8
2009	16.3	16.8	16.7	15.6	17.2	22.2	25.9	27.9	23.8	18.0	16.0	17.5	19.5
2010	18.4	17.9	15.4	16.5	18.8	24.4	29.8	31.4	24.1	19.2	17.3	19.1	21.0
2011	18.2	18.0	16.2	18.2	19.3	24.2	31.2	30.7	23.7	19.3	18.9	20.7	21.6
2012	21.8	23.2	22.7	24.7	27.2	30.4	36.1	33.5	27.8	22.6	20.4	20.3	25.9
2013	21.3	21.2	20.4	19.6	20.7	25.5	30.3	30.0	25.9	21.5	21.0	22.4	23.3
2014	22.4	20.6	19.0	19.3	21.8	25.1	28.2	30.0	26.8	23.6	21.0	21.5	23.3
2015	24.0	24.1	23.9	23.0									

Source: EIA and UBS estimates

Comparing graphically, 2012 remains a clear stand out; we suspect 2015 could approach these levels. Particularly should positive load trends continue (ERCOT has proven resilient amidst lower oil prices, as has NYISO, with positive revisions).

Figure 37: Natural Gas Burn in the Power Stack (Bcf/d)



Source: EIA

Coal reaching new lows, but suspect this could trend lower

Beyond just the weak gas prices, we see weaker weather this summer as putting yet further strain on delivered coal volumes in the electric sector. We suspect May and June will continue to illustrate this phenomenon as historical data is reported.

Figure 38: Electric Sector Demand for Coal ('000 tons)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2008	94,532	86,702	83,373	76,924	81,248	89,532	98,194	95,752	85,545	80,186	80,993	89,353	1,042,335
2009	90,639	74,256	71,990	67,209	70,508	79,071	84,360	86,789	73,705	74,686	73,150	88,320	934,683
2010	90,767	80,209	76,544	67,037	76,061	87,395	94,993	94,786	79,573	70,918	72,756	88,645	979,684
2011	90,208	73,614	72,645	67,128	73,522	84,156	94,304	92,297	76,790	69,605	67,059	73,610	934,938
2012	70,744	62,974	57,468	51,806	62,801	71,656	86,516	82,676	69,478	66,486	69,913	73,217	825,734
2013	74,985	67,141	70,395	60,899	64,737	75,178	83,223	81,984	72,704	66,359	65,902	77,283	860,790
2014	83,600	76,252	72,234	58,151	64,018	74,488	81,580	81,164	69,242	61,323	64,633	67,730	854,415
2015	71,518	67,181	58,445	48,704									

Source: EIA

For more, please see our note: Peak Switching Ahead for Eastern Coal; PRB May be Near a Bottom

How did 2Q15 look for power prices? Quite weak.

Looking at average regional on-peak power prices across the country, most saw average prices decline YoY, albeit sparks did not necessarily. This is indicative of a meaningful acceleration in YoY switching in power prices. We see the lower YoY prices as lending themselves to some amount of pressure to power results in the quarter, although caution that many of the baseload generators are largely hedged for the immediate period.

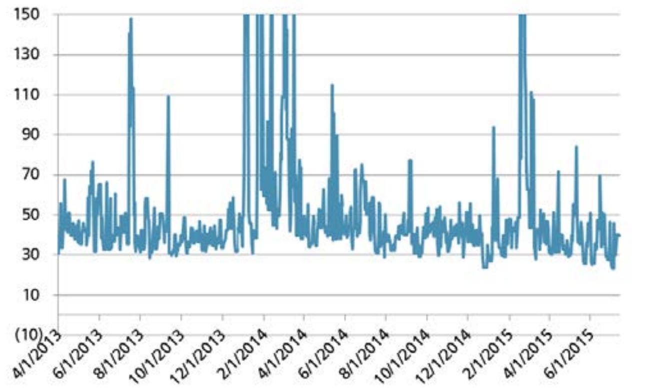
Figure 39: Peak Spot Power Prices

Quarter End	PJM West	PJM East	CAISO	ERCOT	MISO Indiana	MISO Illinois	NEISO	NYISO
6/30/2015	37.7	37.1	25.7	27.2	31.4	29.7	29.0	32.8
3/31/2015	57.4	67.4	32.3	26.5	37.5	31.9	87.0	78.3
12/31/2014	39.9	48.3	43.0	33.6	38.1	35.6	46.1	41.4
9/30/2014	41.6	45.4	49.7	37.1	37.0	36.4	40.7	40.1
6/30/2014	48.3	51.5	45.6	41.0	44.7	46.1	42.9	44.0
3/31/2014	104.5	123.1	53.4	53.3	59.0	50.8	159.3	138.9
12/31/2013	39.6	41.7	44.2	35.6	35.2	32.7	66.6	49.6
9/30/2013	47.5	54.4	46.0	37.7	37.8	36.7	57.5	63.2
6/30/2013	44.3	45.6	43.7	36.3	39.1	37.4	44.9	46.7
6/30/2015 vs 6/30/2014	**-22%**	**-28%**	**-44%**	**-34%**	**-30%**	**-36%**	**-32%**	**-25%**

Source: Bloomberg

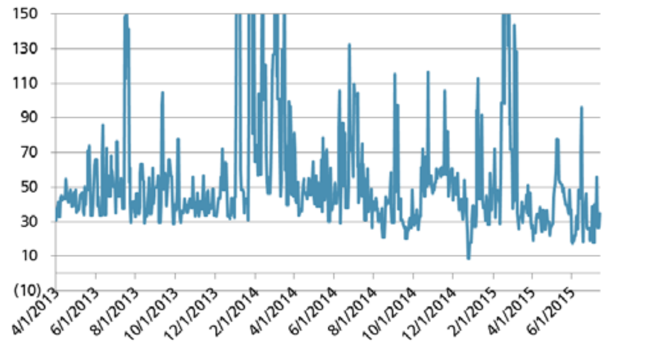
Below we show peak spot prices by market, visually expanding on the Figure above.

Figure 40: PJM West Peak Spot Power Prices



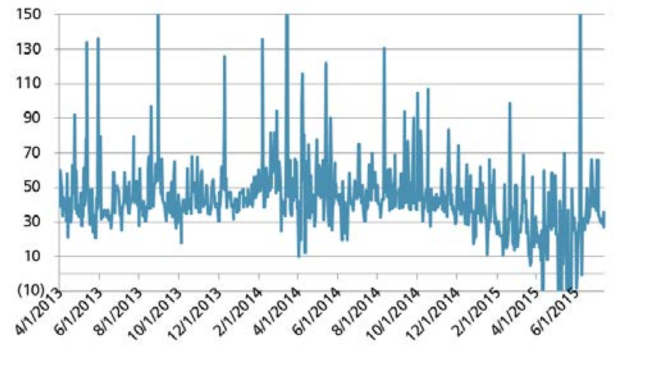
Source: Bloomberg

Figure 41: PJM East Peak Spot Power Prices



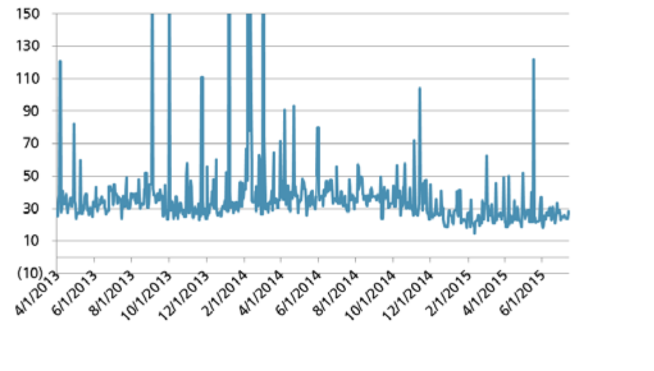
Source: Bloomberg

Figure 42: CAISO Peak Spot Power Prices



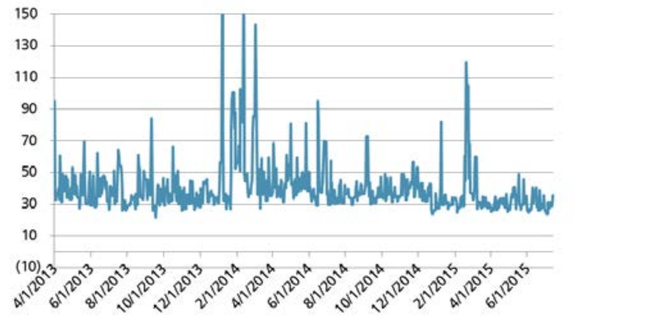
Source: Bloomberg

Figure 43: ERCOT Peak Spot Power Prices



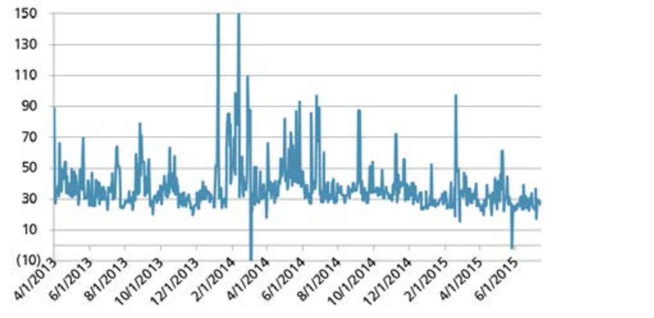
Source: Bloomberg

Figure 44: MISO IN Peak Spot Power Prices



Source: Bloomberg

Figure 45: MISO IL Peak Spot Power Prices



Source: Bloomberg

Additionally we show a similar analysis this time with spark spreads in key markets.

Figure 46: Qtr Avg Spark Spreads @ 7.2 HR

Quarter End	PJM West	PJM East	CAISO	ERCOT	NEISO	NYISO
6/30/2015	26.4	25.8	3.7	26.8	13.1	27.8
3/31/2015	16.5	26.8	10.4	27.8	2.5	28.8
12/31/2014	20.6	27.8	12.9	28.8	8.3	29.8
9/30/2014	24.3	28.8	17.0	29.8	19.0	30.8
6/30/2014	22.4	29.8	9.1	30.8	12.5	31.8
3/31/2014	21.2	30.8	13.6	31.8	13.0	32.8
12/31/2013	11.4	31.8	14.2	32.8	10.3	33.8
9/30/2013	22.1	32.8	18.4	33.8	28.7	34.8
6/30/2013	14.8	33.8	14.3	34.8	11.5	35.8
6/30/2015 vs 6/30/2014	**18%**	**-13%**	**-59%**	**-13%**	**5%**	**-13%**

Source: Bloomberg

And looking more specifically at regional basis trends within PJM

2Q15 basis for all the regions were negative except PEPCO and BGE basis. Most notable drops were in PSEG and PPL basis, both turned negative during 2Q. However, AD, NI and ATSI basis were improved considerably from 1Q. YoY comparison revealed similar trend, and except PEPCO and BGE all were down on Y-o-Y basis. While gas prices were down significantly, we believe basis differentials were under pressure from subdued summer heat and existing gas transmission constraint. We note heat rate was down compared to 1Q15.

Figure 47: Average PJM Regional LMP Prices, by Zone ($/MWH)

Avg LMP Price	2015	2Q15	1Q15	2014	4Q14	3Q14	2Q14	1Q14	2013	4Q13	3Q13	2Q13	1Q13	2012	2011	2010	2009	2008
West Hub	41.83	33.12	50.64	51.01	36.00	35.78	41.43	91.63	38.42	37.86	39.48	38.80	37.51	33.89	43.59	46.59	39.25	69.81
Henry Hub	2.81	2.64	2.98	4.41	4.00	4.06	4.67	4.94	3.65	3.60	3.58	4.09	3.34	2.79	4.04	4.39	3.99	8.99
Heat Rate	14.9x	12.5x	17.0x	11.6x	9.0x	8.8x	8.9x	18.6x	10.5x	10.5x	11.0x	9.5x	11.2x	12.1x	10.8x	10.6x	9.8x	7.8x
PSEG	45.42	28.51	62.51	56.96	35.38	33.82	41.41	118.40	41.93	40.18	41.63	41.15	44.82	34.76	48.32	50.89	42.40	79.78
Basis	3.59	(4.61)	11.88	5.95	(0.62)	(1.96)	(0.02)	26.77	3.52	2.33	2.15	2.35	7.30	0.86	4.72	4.30	3.14	9.96
PPL	42.26	27.71	56.97	52.13	33.38	32.20	38.56	105.41	38.01	37.03	39.60	38.58	36.80	33.19	45.68	47.67	40.42	74.25
Basis	0.43	(5.41)	6.33	1.12	(2.61)	(3.57)	(2.88)	13.77	(0.41)	(0.82)	0.12	(0.22)	(0.72)	(0.70)	2.09	1.08	1.17	4.44
PEPCO	47.78	37.83	57.84	58.27	38.97	40.05	44.76	110.28	41.04	40.56	41.89	41.23	40.48	36.05	47.58	52.94	43.12	81.26
Basis	5.95	4.72	7.20	7.25	2.97	4.27	3.32	18.65	2.63	2.70	2.41	2.43	2.97	2.16	3.99	6.36	3.86	11.45
BGE	50.30	41.67	59.03	60.22	40.71	42.62	46.54	111.98	41.53	40.77	42.73	42.18	40.41	36.91	48.51	53.24	43.14	80.71
Basis	8.47	8.56	8.39	9.20	4.71	6.85	5.11	20.35	3.11	2.91	3.25	3.38	2.89	3.02	4.92	6.36	3.89	10.89
AD Hub	34.66	31.34	38.02	44.09	35.39	33.06	40.32	68.07	35.01	34.06	35.55	36.35	34.06	31.22	38.69	37.58	33.38	53.19
Basis	(7.17)	(1.78)	(12.62)	(6.93)	(0.61)	(2.71)	(1.11)	(23.56)	(3.41)	(3.80)	(3.93)	(2.45)	(3.45)	(2.67)	(4.91)	(9.00)	(5.87)	(16.63)
NI Hub	29.40	25.18	33.67	39.93	31.49	31.06	36.63	60.98	32.20	30.99	33.50	33.16	31.13	28.57	33.24	33.13	29.22	50.04
Basis	(12.42)	(7.94)	(16.96)	(11.08)	(4.51)	(4.71)	(4.81)	(30.65)	(6.22)	(6.87)	(5.98)	(5.64)	(6.38)	(5.32)	(10.35)	(13.46)	(10.04)	(19.77)
ATSI Hub	36.69	32.60	40.82	50.01	35.60	34.18	41.69	74.61	36.54	36.02	37.85	37.31	34.94	32.11	39.34			
Basis	(5.14)	(0.51)	(9.82)	(4.64)	(0.42)	(1.60)	0.26	(17.03)	(1.88)	(1.83)	(1.64)	(1.49)	(2.57)	(1.78)	(3.05)			
AD - NI Hub Basis	5.26	6.16	4.34	4.15	3.90	2.00	3.69	7.09	2.81	3.07	2.04	3.19	2.93	2.65	5.45	4.46	4.16	3.15

Source: PJM and UBS estimates

The Commodity Forward Outlook

In the next section, we look at the latest shifts in forward power prices, heat rates.

Heat Rate Backwardation Remains Across Most Markets

We include the latest power forwards for the curve annually to illustrate backwardation by region. We emphasize backwardation in power markets appears to be increasing, with PJM seeing a meaningful falling off as gas prices appear to normalize. Notably, PJM heat rates remain exceptionally backwardated vs. all other markets, reflecting continued expectations for new build. In contrast, the ERCOT market reflects the least backwardation, reflecting more promising expectations for demand to absorb new demand.

Figure 48: Forward ATC Heat Rates (MWh/MMBtu) by Power Market

	2016	2017	2018	2019
NP15 / PG&E	11.41	10.71	10.36	10.50
YoY % Change		-6.1%	-3.3%	1.4%
ERCOT-S/Houston Shipping	11.18	11.27	11.14	11.30
YoY % Change		0.8%	-1.1%	1.4%
NYISO Zn G / Transco Zn 6	12.75	12.31	12.01	12.14
YoY % Change		-3.4%	-2.5%	1.1%
Southern / Transco Zn 4	11.02	10.48	10.34	10.50
YoY % Change		-4.9%	-1.3%	1.5%
Mass Hub / Algonquin	10.64	11.29	11.04	11.15
YoY % Change		6.1%	-2.2%	1.0%
Entergy / Henry Hub	11.95	11.50	11.35	11.51
YoY % Change		-3.8%	-1.3%	1.4%
NI Hub / Chicago Citygate	12.07	11.50	10.94	11.10
YoY % Change		-4.7%	-4.9%	1.5%
PJM West / TETCO M3	15.71	13.69	12.91	13.08
YoY % Change		-12.9%	-5.7%	1.3%
AD Hub / MichCon	13.17	12.48	11.99	12.15
YoY % Change		-5.3%	-3.9%	1.4%
ERCOT-Houston/Houston Ship	11.42	11.53	11.40	11.55
YoY % Change		1.0%	-1.2%	1.4%
ERCOT-West/Houston Ship	10.75	10.75	10.57	10.73
YoY % Change		0.0%	-1.6%	1.5%
ERCOT-North/Houston Ship	10.94	10.97	10.86	11.01
YoY % Change		0.3%	-1.0%	1.4%
CIN-Hub/ Chicago Citygate	12.34	12.19	12.05	12.22
YoY % Change		-1.2%	-1.1%	1.4%
Average		*-2.6%*	*-2.4%*	*1.3%*
1Q15 Average		*-3.5%*	*-2.7%*	*1.3%*
4Q14 Average	*-4.2%*	*-4.2%*	*-2.5%*	

Source: Platts and UBS estimates

Regional Heat Rates: Coal Provides Heat Rate Upside

We also include ATC Heat rate change YoY for 2016 forward delivery to illustrate the changes in the last year.

Marginal coal regions have seen sparks expand substantially

- *We see the massive improvements in heat rates across many coal-centric markets as a reflection of continued de-linking between gas and power prices, with coal increasingly setting the marginal price of power.*
- ERCOT Heat rates have remained stable following continued negative trends in spark spreads in the quarter.
- While the Northeast (NYISO upstate and Mass Hub) markets have improved the most and Midwest markets and PJM appear to have seen substantial improvements in heat rates, a notable exception is MidC, which has continued to lag the rest.

Figure 49: ATC Heat Rates – Change YoY for Forward 2016

ATC Heat Rates 2016						
	ERCOT-North	ERCOT-Houston	ERCOT-West	ERCOT-S	Entergy	Southern
Jul-15	9,195	9,934	9,324	9,491	10,509	9,989
Jul-14	9,149	9,977	9,019	9,268	7,454	8,197
YoY % Change	1%	0%	3%	2%	41%	22%
	NY-ZnG	NY-ZnJ	NY-ZnA	MassHub		
Jul-15	10,734	11,260	10,581	9,243		
Jul-14	11,644	12,395	8,868	8,548		
YoY % Change	-8%	-9%	19%	8%		
	PaloVerde	SP15	NP15	MidC		
Jul-15	11,653	11,111	10,143	8,541		
Jul-14	9,609	10,213	8,954	8,436		
YoY % Change	21%	9%	13%	1%		
	Indy Hub	NI Hub	ADHub	PJM-W		
Jul-15	10,597	9,869	11,373	13,028		
Jul-14	8,305	8,021	8,943	9,865		
YoY % Change	28%	23%	27%	32%		

Source: Platts/ Bloomberg

Forward Price Moves in The Quarter: Flattish

The remarkable stability in 2016 forwards is striking. Given the sharp declines in forward gas prices, we see the relative paucity of forward price erosion as reiterating our thesis that coal now drives power prices.

Despite recent volatility, changes QoQ are limited

We flag the gas thesis remains focused on the Mid-Atlantic markets, with continued upward surprise production from both the Marcellus and Utica shales. The question remains whether an expected acceleration in shoulder season will prove a meaningful headwind. *IPP and diversified utility forward guidance revisions should be largely minimal.*

Capacity Price Forecasts by Region

We include our forecast across all the key power markets in the US. Please see our latest thinking on capacity pricing convergence here.

Figure 50: Capacity Price Forecast, by Market

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
PJM ($MW-day)												
RTO	111.9	102.0	174.3	110.0	16.5	27.7	126.0	136.0	59.4	120.0	160.0	
EMAAC	148.8	191.3	174.3	110.0	139.7	245.0	136.5	167.5	119.1	120.0	160.0	
SWMAAC	210.1	237.3	174.3	110.0	133.4	226.2	136.5	167.5	119.1	120.0	160.0	
MAAC				110.0	133.4	226.2	136.5	167.5	119.1	120.0	160.0	
DPL-S			186.1	110.0	222.3	245.0	136.5	167.5	119.1	120.0	160.0	
PS-N					185.0	245.0	225.0	167.5	219.0	215.0	160.0	
PSEG					139.7	245.0	136.5	167.5	219.0	215.0	160.0	
PEPCO						247.1	136.5	167.5	119.1	120.0	160.0	
ATSI								357.0	114.2	120.0	160.0	
Comed Breaks out too?												
ISO-NE												
Annualized ($/kW-Month)	3.65	3.95	4.19	3.59	2.78	2.53	2.72	3.02	2.99	5.30	8.50	7.48
Clearing Price/Pro-Rated	3.75	4.10	4.25	3.12	2.54	2.52	2.86	3.13	2.88	7.03	9.55	6.00
NYISO - Zn J												
Summer ICAP ($/kW-month)	6.50	6.75	12.90	13.54	11.70	14.80	16.24	14.00	14.00	14.00	14.00	
Winter ICAP ($/kW-month)	1.91	2.79	4.65	4.60	2.70	4.50	7.54	8.45	8.45	8.45	8.45	
NYISO Zn J ($/kW-month)	4.35	5.08	8.77	8.75	7.50	10.16	12.04	11.23	11.23	11.23	11.23	
NYISO Zn J ($/kW-yr)	52.22	60.96	105.20	105.04	90.00	121.88	144.50	134.70	134.70	134.70	134.70	
NYISO - RoS												
Summer ICAP ($/kW-month)	2.67	3.01	2.47	0.55	1.25	5.80	5.15	4.00	3.75	3.75	3.75	
Winter ICAP ($/kW-month)	1.91	1.77	1.75	0.39	0.15	0.82	2.58	2.90	2.65	2.40	2.50	
NYISO - RoS ($/kW-month)	2.27	2.39	1.88	0.43	0.81	2.80	3.92	3.41	3.16	3.09	3.13	
NYISO - RoS ($/kW-yr)	27.20	28.64	22.60	5.16	9.74	33.64	47.02	40.90	37.90	37.10	37.50	
MISO Capacity Value:												
IPA Auctions ($/kW-yr)	12.41	8.46	0.67	0.18	3.70	7.64	16.75					
Calendarized ($/kW-yr)		10.44	4.57	0.43	1.94	5.67	12.20					
MISO RA Auction ($/MW-day)						1.05	16.75	150.00	59.37	120.00	150.00	
Calendarized ($/KW-yr)							3.73	34.48	35.45	34.58	50.19	

Source: Company reports and UBS estimates

American Electric Pwr (Neutral; $54 PT)

Utility growth offsets the well telegraphed GenCo decline leaving a flat quarter. 2H15 critical with respect to PJM datapoints that help shape valuation of GenCo and influence management's strategic review.

No real surprises expected this quarter with slight drop YoY.

We forecast AEP reporting adjusted 2Q15 EPS of **$0.78**, down slightly YoY but in-line with Consensus ($0.79). The utilities collectively are expected to improve +$0.06 due primarily to higher rates (+$0.05) with weather (-$0.03) and off-system sales (-$0.02 the primary offsets. We still assume slight load growth despite the -1.3%YoY in 1Q15 as we see comparisons with the Polar Vortex as challenging. Improvement at the regulated utilities is more than offset by generation weakness which drives our ~flat quarterly estimate. 1Q15 at the GenCo was up +$0.05 due to strong trading and marketing (+$0.04) but we anticipate a reversion to the negative trend implied in guidance given YoY power and capacity headwinds. FY15 GenCo guidance is down $0.38/sh, or $155Mn adjusted EBITDA.

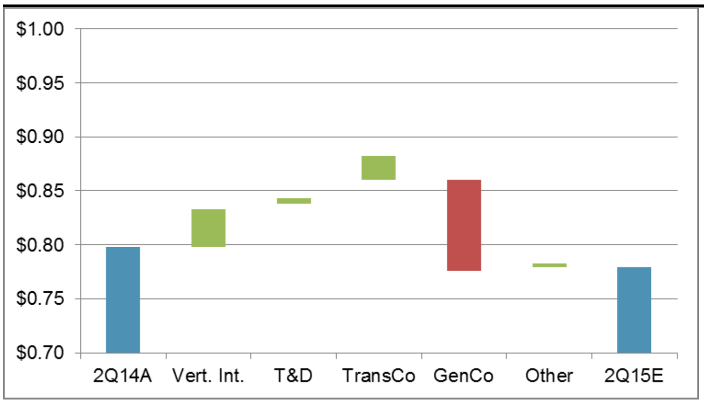
We do not anticipate that management will change its FY15 guidance range of $3.40-$3.60 at this time.

Figure 51: AEP 2Q15 Earnings Walk

2Q15E AEP Earnings Walk	EPS
2Q14A Adjusted EPS	**$0.80**
Vertically Integrated Utilities	**$0.03**
Rate Changes	0.04
O&M	0.02
AFUDC	0.02
Weather	(0.03)
Return to Normal	(0.01)
Current Quarter	(0.02)
Off-System Sales (OSS)	(0.02)
Normal Load	0.01
Depreciation and Other	(0.01)
Trans. & Distribution Utilities	**$0.01**
Rate Changes	0.01
O&M	0.01
Depreciation	(0.01)
Normal Load, Depreciation, & Other	(0.01)
Transmission HoldCo	**$0.02**
Generation & Marketing	**($0.08)**
AEP River Operations	**$0.00**
Corporate & Other	**$0.00**
2Q15E Adjusted EPS	**$0.78**
2Q15 Consensus	**$0.79**
2015 Guidance	**$3.40-$3.60**
2015 UBSe	**$3.49**
2015 Consensus	**$3.53**

Source: Company Filings, FactSet and UBS Estimates

Figure 52: AEP 2Q15 Earnings Walk: $0.80 → $0.78 YoY



Source: Company Filings and UBS Estimates

For more detail on these issues, please see our other recent reports:

4/27/15 Powerful Start to an Uncertain Year
[3/19/15 More March Madness in Columbus]
[2/25/15 Purchase Power Placeholder]

What's new with AEP?

Regulatory Staff is expected to file testimony on the proposed PPA on July 10. There is no statutory deadline for a decision.

- **Potential asset sale awaits Ohio PPA outcome, which is pending PJM capacity auction results:** AEP discussed at length on its 1Q15 earnings call the strategic review of its unregulated merchant portfolio. AEP filed its latest amended ESP in Ohio with a revised PPA request which management argues could generate $574Mn of bill credits over the next ten years with an incremental ~$200Mn from Capacity Performance accruing to customers. This compares with AEP's original rider which had a projected ten-year benefit of $224Mn for customers. The proposed ~20 year PPA covers 3.1GW of generation (including 423MW of OVEC entitlement) with estimated ratebase of $1.6Bn. The PPA would be under FERC jurisdiction with an initial ROE of 11.2%.

  Fundamentally, the strategic rationale for a sale of AEP's non-regulated generating fleet remains the removal of merchant volatility from earnings. Spin vs sale would be considered based on best value creation for shareholders; however management's recent statements on the issue would indicate to us a preference for a sale rather than a spin. A sale/spin awaits certain valuation markers to trigger the disposition decision, foremost among them a final decision on PPAs from Ohio regulators (or the lack of a decision) and the outcome of the PJM capacity auction later this summer. Ohio regulators are themselves awaiting the outcome at PJM to base their decision on PPAs. Regulatory Staff is expected to file testimony on the proposed PPA on July 10. Although there is no statutory deadline for a decision, AEP has requested that the proceedings take place on an expedited basis in June/July to facilitate a Commission decision by October 1st. Docket: 13-2385-EL-SSO

- **Reinvestment of proceeds likely going toward transmission:** Proceeds from any potential generation divestiture are likely to be put toward projects at both the vertically integrated utilities as well as the Transmission Holdco. However, it would likely take at least a "couple of years" to redeploy the cash and management has discussed mitigating earnings dilution in the interim through a variety of methods including possible share repurchases, if necessary. In considering accretion from a sale, we note that currently AEP earns an 11.49% ROE in PJM and 11.20% in SPP.

  In terms of potential places to expand, the company's 2015-2017E base capex plan already has $1.9B of transmission capex at the utilities and another $2.9B at the independent Transmission Holdco that could expand by an additional $1.8B of ratebase through 2018 under management's "high case" planning. These projects generally include local reliability, aging infrastructure, customer-driven projects, and regional projects for retirements, renewables, economic and market efficiencies. Excluded from this forecast are any additional upside from potential FERC 1000 competitive projects and other possible government mandates such as security spending.

  Despite wider negativity around transmission capex trends in the space, we have yet to observe such a slowdown on PJM oriented plays, which continue to emphasize lower-voltage upgrade projects (which don't require review process

through PJM albeit still qualify for FERC formula rates) as the source of incremental capital. We suspect the limits of this incremental deployment opportunity could well be stressed by sell-down of the generation business.

- **Rate settlements for KY and WV:** On June 22, AEP's settlement for Kentucky Power was approved (was filed on April 30) for a -$23M base rate reduction based on a 10.25% ROE and 43.93% equity. This compares to 2.4% in 1Q15 and previous guidance of 8.3% for FY2015E. However, while the base rate was reduced, this is more than offset by increases for $68.4M of various rate riders, including a rider to recover retirement costs for the Big Sandy coal plant retirement, another for remaining non-fuel operating costs for Big Sandy, and an Environmental Surcharge rider for equipment installation at the Mitchell plant. As a result of the riders, we expect a marked improvement in ROE for 2016 (and some in 2015).

  In West Virginia, APCo received a $123M rate increase on May 26 based on a 9.75% ROE and 47.16% equity for $3.7B of ratebase and a 2013 test year (average). This compares to 8.4% in 1Q15 and previous guidance of 8.5% for FY2015E. However, within APCo, WV has typically been earning closer to ~5% ROE, so we expect the rate increase to result in a forward improvement here as well. AEP expects to file a new base rate request in Oklahoma later in the summer, where the company earned 9.2% ROE in 1Q15 and expects to earn a 9.2% ROE in FY 2015E. PSO is currently authorized a 9.85% ROE.

As a result of the riders, we expect a marked improvement in ROE for 2016 (and some in 2015).

All quiet? No meaningful rate cases for time being

- **No welcome mat for MATS Supreme Court decision:** AEP disclosed with 1Q15 that it was retiring 5,750MW of capacity in May related to MATS and subsequently confirmed that it would not be reversing that decision following the Supreme Court decision that the EPA unreasonably determined that costs were irrelevant in its power plant regulation standard and remanded the case to the Washington DC Circuit Court.

- **Grid Assurance – new consortium to address reliability/ resiliency:** This will be a new company formed as a consortium of utilities, which includes American Electric Power (AEP), Duke Energy (DUK), Edison International (EIX), Eversource Energy (ES), Exelon Corporation (EXC), Great Plains Energy (GXP), Southern Company (SO) and Berkshire Hathaway Energy. The company has filed for FERC approval although would not be regulated by FERC.

  If approved the consortium should have a favorable impact on O&M, outage restoration time, and working capital but is unlikely to have a material financial impact as O&M is a pass-through for the regulated names. Grid Assurance's business model is to charge a cost-based subscription fees, similar to FERC-regulated transmission formula rates.

Estimates and MTM

With declining power forward pricing in the last several of months, it's not surprising to see our 8x 2017E-based EV/EBITDA valuation for the GenCo dip ~$135M (-$0.27/sh) since our April update. Since we already embed this value in our sum-of-the-parts price target (see below), **the impact of a sale with stock repurchases remains essentially neutral.**

Figure 53: AEP Genco UBSe EBITDA and Estimated Value at 8x EV/EBITDA – using Latest MtM

AEP Generation Resources PJM Mini-Model	2015E	2016E	2017E	2018E
(Open) Energy Gross Margins [Generation Only]	513	424	368	337
Retail Margin	30	30	30	30
Capacity Revenues	355	246	255	324
PUCO Transition FRR Non-Bypassable Revenues	69	-	-	-
Other/Hedges (unswitched customer assumption)	14	(40)		
Subtotal Energy/Capacity Gross Margins	980	661	653	690
Guidance (EEI Nov 2014)	*965-1035*	*590-790*		
O&M	(410)	(340)	(316)	(316)
Guidance (EEI Nov 2014)	*(410)*	*(340)*		
EBITDA	570	321	337	375
Value at 8x EV / EBITDA	4,563	2,565	2,699	2,996
Previous UBSe (April 2015)	*4,563*	*2,583*	*2,982*	*3,616*

Source: UBS Estimates, Company filings

As illustrated below, we see at least $2.65 of accretion assuming a 10.84% ROE as a lower-end possible outcome at FERC for future transmission projects based on the "midpoint" methodology within an updated "zone of reasonableness". Assuming repurchases of shares, there is limited upside to divestment aside the improved risk profile. As such, we see AEP divestment as less relevant than to peers like AEE facing negative genco EPS projections when divested.

Figure 54: Accretion (Dilution) of GenCo Sale – Two Approaches

Status Quo Valuation to GenCo		
EPS	$	0.14
Group Multiple		14.7x
P/E Value to Genco	***$***	***2.11***
EBITDA	$	337
EV/EBITDA		8.0x
EV		2,699
Debt		(826)
Equity Value via SOP	***$***	***3.78***
Sale Accretion (Dilution) Value - Share Repurchases		
Shares Bought Back		33
Repo value on Buyback	***$***	***3.81***
Accretion vs. EV/EBITDA	*$*	*0.04*
Sale Accretion (Dilution) Value - Reinvestment in Transmission		
Equity	$	1,873
Net Income at 10.84% ROE	$	203
Value at 15.7x multiple	$	3,187
Value/sh	***$***	***6.43***
Accretion vs. EV/EBITDA	*$*	*2.65*

Source: UBS estimates

Valuation: Reduce Price Target to $4

Our valuation methodology is unchanged and we still utilize a 2017E sum-of-the-parts analysis. We continue to account for the Genco on an EV/EBITDA basis.

Figure 55: American Electric Power 2017E Sum-of-the-Parts

American Electric Power Sum-of-the-Parts Analysis	2017E EPS	P/E & EV/EBITDA Multiples				Enterprise Value		
	EPS	Low	Base	(Discount)	High	Low	Base	High
Vertically Integrated Utilities	$2.86	13.7x	14.7x	-5%	15.7x	$19,396	$19,771	$22,227
Transmission Utilities	$0.62	14.7x	15.7x	0%	16.7x	$4,481	$4,786	$5,090
Parent & Other	$0.03	13.7x	14.7x	-5%	15.7x	$194	$197	$222
Total Regulated	**$3.50**	**13.9x**	**14.3x**	**-3%**	**15.9x**	**$24,070**	**$24,754**	**$27,539**
	EBITDA	Low	Base	(Discount)	High	Low	Base	High
GenCo	$337	7.0x	8.0x	0%	9.0x	$2,361	$2,699	$3,036
Less: Net Debt						($826)	($826)	($826)
Total GenCo						**$1,535**	**$1,873**	**$2,210**
Total Value						**$25,605**	**$26,626**	**$29,749**
Shares Outstanding (2017E)						496	496	496
Total Value per Share						**$52.00**	**$54.00**	**$60.00**

Source: Company Filings, FactSet, and UBS Estimates

Ameren Corp. (Neutral; $40 PT)

Investors' focus turns from Missouri to Illinois with latest ROE datapoint also somewhat concerning. Mgmt will have to show ability to earn its new MO ROE as well.

Coming off a robust 2Q14 we see 2Q15 as moderating but the second half of the year should show improvement.

We forecast AEE reporting adjusted 2Q15 EPS of **$0.58**, down YoY from a strong 2Q14 ($0.62) due primarily to unfavorable weather comparisons and representing a miss versus Consensus ($0.64). The decline in degree days in 2Q15 was not as pronounced as the above-average degree days in 2Q14; therefore, we see a more modest decline this quarter. Weather was a +$0.04 benefit vs normal in 2Q14 and we estimate -$0.02 decline in 2Q15. Aside from the weather headwind, we estimate largely flat earnings with organic growth in ratebase offset by regulatory lag (Missouri) and reduced ROE (FERC jurisdictional assets). Specifically the combination of a full quarter of depreciation/property taxes and lost AFUDC is offset by only one month of new rates in Missouri. Based upon our 2Q15 estimate, we see TTM EPS of $2.41 which lags behind our FY15 estimate of $2.51 due to an expected pickup in 2H for weather normalization (+$0.08) and the lack of a Callaway nuclear outage (+$0.08), although there are offsets.

Figure 56: AEE 2Q15 Earnings Walk

2Q15 YoY Earnings Walk		
2Q14A	**$0.62**	Notes
Weather vs. Normal in 2Q14	(0.04)	*Above-average CDDs in Quarter*
Weather vs. Normal in 2Q15	(0.02)	*Below-average CDDs in service territory*
MO Electric: New Rates	0.00	*Regulatory lag in 1H15; new rates May 30*
IL Electric: Formulaic Rates (Higher rate base)	0.00	*Rate increase for Jan '15; FY EPS impact of 50bp Δ in ROE is ~$0.025*
IL: Infrastructure Surcharge Framework	0.00	*Immaterial contribution in 2015*
ATX and IL Transmission	(0.00)	*Avg Ratebase increase YoY for FERC Trans. is $500M Higher in '15*
Lower Interest Expense	0.01	*Refinancing of 8.9% Parent Notes in May 2014 (Partial Q Benefit)*
Lower Effective Tax Rate	0.01	*~38% ETR Guidance '15 vs 37% '15 Guidance*
Change in O&M, D&A, Opex	(0.00)	*Cost Inflation*
2Q15E Adjusted EPS	***$0.58***	
2Q15E Consensus	*$0.64*	
2015 Guidance	*$2.45-$2.65*	
2015 UBSe	*$2.48*	
2015 Consensus	*$2.55*	

Source: Company Filings, FactSet, and UBS Estimates

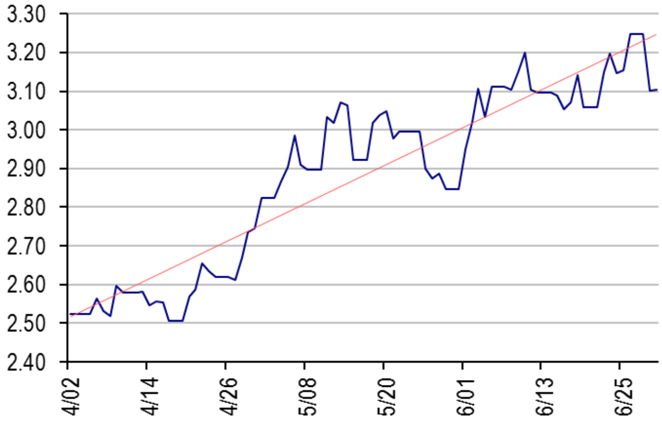
For additional context, please refer links to relevant recent reports below:

5/8/15 Show Me the Growth in Missouri
2/25/15 Floating Down The Illinois River
11/7/14 Robust and Regulated
10/24/14 How Low Could Transmission ROEs Go?

Figure 57: 30-Year US Treasuries: Long-Term View

Source: FactSet

Figure 58: 30-Year US Treasuries: Quarter View



Source: FactSet

What's new with AEE?

- **Illinois Gas rate case hearings set for this summer –Staff recommends 9.3% ROE:** In June the ICC Staff recommended a 9.31% ROE in Ameren's pending natural gas rate case versus Ameren's 10.0-10.5% request. For reference WEC and TEG received 9.05% ROEs in their latest rate cases (1Q15 ruling) with similar 10.25% ROE requests as Ameren. Ameren originally filed the case in January to recovery gas transmission, storage, and distribution infrastructure. Management also requested a revenue decoupling mechanism aimed at residential and small customers. The Staff supported the approval of decoupling rider noting that Peoples Gas has a similar rider, the legality of which was affirmed in a January IL Supreme Court ruling. Hearings are scheduled for late August with a tentative ALJ proposed order on November 3rd. Ameren filed rebuttal testimony on July 8th supporting its ROE range.

Initial Staff recommendation ~100bp below Ameren's request but higher than recent authorizations for WEC/TEG.

Figure 59: Illinois Rate Case Timeline

D-15-0142 Procedural Schedule	
Case Event	*Date*
ICC Staff & Intervenor Testimony	June 9
Evidentiary Hearings	August 24-27
ALJ Proposed Order	November 3
Final Order Deadline	December 19
New Rates Effective	January 2016

Source: Company Filings

Figure 60: Illinois Rate Case AEE vs ICC Staff

IL Gas Case: D-15-0142	Ameren	Staff
Rate Change ($Mn)	$52.7	$41.6
Rate Base ($Bn)	$1.2	$1.2
ROE (%)	10.25%	9.31%
Equity Ratio (%)	50%	50%

Source: SNL Energy

Ameren also has an $110Mn electric formula rate case outstanding which was filed in April based on the recently extended EIMA mechanisms (580bp plus 30-year US Treasury yield). Docket D-15-0305

- **Requesting another review of the Missouri rate case:** Ameren is appealing its recent Missouri rate case outcome to the Missouri Court of Appeals following the Commission's decision to deny the rehearing request. Ameren argues that the 9.53% ROE awarded is inadequate given the risks of operating a single-unit nuclear among other factors. The appeal also requests review of omission of transmission expenses in the Fuel Adjustment Clause (FAC) and the Commission's decision to not normalize Noranda's expected load.

Ameren is appealing its MO case to the state court of appeals as the Commission denied the rehearing request.

- **Breaking up with Noranda is hard to do:** In June Noranda reported that it received a notice of termination from Ameren's Missouri utility Union Electric regarding its electric supply contract signed in December 2004. Ameren has a 15-year electric agreement with Noranda which is subject to early termination beginning in 2020 contingent on providing five's year notice. Noranda disclosed that it could seek to negotiate with Ameren or pursue an alternative supplier but it believes Ameren has an obligation to provide electricity. Ultimate contract termination is subject to Missouri Public Service Commission review and approval; it remains to be seen how the Commission will act

Ameren notified Noranda that it intends to terminate its electric supply contract in five years.

In Ameren's recent rate case Noranda had its base rate reduced to $36/MWh from $42.35/MWh versus a request for $34/MWh. The Commission rejected the $34/MWh as too low arguing that Noranda should not have a favorable electric rate versus other aluminum peers but should at least be competitive. Additionally the Fuel Adjustment Clause is now capped at $2/MWh compared with $4.40/MWh recently charged. Contingencies on the deal include that Noranda must spend $35Mn in capex annually and cannot be involved in M&A. The Commission's creation of an Industrial Aluminum Smelters (IAS) class lasts for three years but rates will remain effective until adjusted. As the PSC points out, while the terms are binding on Ameren and Noranda, the Commission can still revise the terms in the future.

The lower revenue collected from Noranda is offset by higher rates for Ameren's remaining Missouri customers leaving the company revenue neutral; however, this puts a burden on remaining customers. We see this as the latest dustup with Noranda, potentially placing further pressure on ability to execute legislative reform in coming years.

- **Continuing to make progress on transmission projects:** Steps were taken forward on the three large Multi-Value Projects (MVP):
  - **Mark Twain**: Requested Certificate of Public Convenience and Necessity (CPCN). Management has requested a final Commission order before February 2016
  - **Illinois Rivers:** All signs indicate that the $1.4Bn project is on-track in the early days of the approximate four-year construction cycle.
  - **Spoon Rivers:** Requested CPCN with decision expected in 3Q15.
- **Also bulking up on solar before ITC step-down:** Ameren recently requested approval for 15MW of solar in Missouri to help meet the state's RPS. Management has requested approval by September 5th and plans to have the asset completed by YE16 in time to take advantage of the 30% solar ITC.

Estimates slightly higher

We have increased our Illinois EPS estimates slightly but still remain below consensus. Further improvement in the earnings trajectory in Illinois could come from a sustained increase in interest rates due to the EIMA, providing some protection against rising rate concerns on a macro level. The 30-Year treasury was recently around 3.0%, up meaningfully from 2.6% at the close of 1Q.

Figure 61: Updated Ameren Earnings Estimates

Consolidated EPS Projections	2013A	2014A	2015E	2016E	2017E	2018E
Ameren Missouri	1.62	1.60	1.55	1.57	1.62	1.67
Ameren Illinois	0.65	0.82	0.85	0.90	0.95	0.99
ATX	0.03	0.06	0.13	0.20	0.26	0.32
Other	(0.21)	(0.08)	(0.02)	(0.03)	(0.05)	(0.02)
Total EPS	2.10	2.40	2.51	2.63	2.78	2.96
Prior	*2.10*	*2.40*	*2.48*	*2.61*	*2.76*	*2.93*
YoY Growth Rate	*-13%*	*15%*	*4%*	*5%*	*6%*	*6%*
Consensus	2.07	2.40	2.55	2.68	2.85	2.98
Projected ROEs, by Utility (regulatory basis)						
Missouri	9.89%	9.77%	9.33%	9.24%	9.33%	9.36%
Illinois	7.99%	9.41%	9.06%	9.36%	9.62%	9.85%
Weighted Average ROE Earned (regulatory)	9.26%	9.64%	9.25%	9.28%	9.41%	9.50%
Guidance			*\$2.45-\$2.65*			
Low Implied Guidance Range (7%)	*2.10*	*2.24*	*2.40*	*2.57*	*2.75*	*2.94*
High Implied Guidance Range (10%)	*2.10*	*2.30*	*2.54*	*2.79*	*3.07*	*3.37*
'13-'18 Guidance EPS CAGR		*7-10%*	*'14-'18 Guidance EPS CAGR*			*6%-9.5%*
'13-'18 UBSe EPS CAGR		*7.2%*	*'14-'18 UBSe EPS CAGR*			*5.4%*

Source: Company Filings, FactSet, and UBS Estimates

Valuation: Lowering Price Target by $1 to $40

We continue to apply a 2017E sum-of-the-parts valuation methodology and are lowing our Price Target by $1 to account for the lower group multiple since our last update.

Figure 62: Updated Ameren Valuation

Ameren Sum of the Parts Valuation - 2017E UBSe									
All figures in US $ million except per share data	EPS	P/E Multiple					Equity Value		
		Low	Peer Multiple	Prem /Disc	Base	High	Low	Base	High
Ameren Missouri	$1.62	12.7x	14.7x	-1.0x	13.7x	14.7x	$5,036	$5,433	$5,829
Ameren Illinois	$0.95	14.2x	14.7x	0.5x	15.2x	16.2x	$3,302	$3,535	$3,768
Ameren Transmission (ATXI)	$0.26	14.7x	15.7x	0.0x	15.7x	16.7x	$925	$988	$1,051
Parent Unallocated Items	($0.05)	13.7x	14.7x	0.0x	14.7x	15.7x	($155)	($166)	($178)
Total / Implied Utilities	$2.78	13.4x			14.4x	15.4x	$9,108	$9,789	$10,469
2017E Number of Shares Outstanding (Mn)							245	245	245
Equity Value per Share							$37.00	$40.00	$43.00

Source: Company Filings, FactSet, and UBS Estimates

Avista Corp. (Neutral, PT $31)

Lower comp vs last year as a result of 1x $0.09 gains in 2014

We expect Avista to report **$0.44** *(no consensus)* vs $0.52 a year ago (excluding the $68M net gain on the sale of Ecova) as a hot June, sales growth, and rate relief are offset with modestly lower year-over year ERM benefits and higher O&M, D&A, and share dilution resulting from the halted stock repurchase plan this year (only 2.5M shares repurchased instead of original plan for 4M). As a reminder, the company booked a net after-tax $0.09 1x gain in 2Q14 as a result of a $15M gain on the settlement of California power markets litigation offset by $6.4M charitable donation to the Avista Foundation.

Figure 63: AVA 2Q15E vs 2Q14A Walk

2Q15E Earnings Walk	EPS
2Q14 Adjusted EPS	**$0.52**
Weather	$0.02
Sales Benefit	$0.03
ERM Benefit	($0.03)
Rate Relief	$0.05
AERC	$0.02
O&M	($0.02)
D&A	($0.03)
Interest	($0.00)
Dilution	($0.02)
2Q14 Energy Mktg CA Lit Settlement	($0.09)
Other	$0.00
2Q15E Adjusted EPS	**$0.44**
Consensus	**$0.53**
2015 Guidance	**$1.86-$2.06**

Source: UBS estimates, Company filings, FactSet

Figure 64: AVA Expected Rate Relief 2Q15

Rate Relief ($M)		
$	7.0	WA - Electric (Jan 2015)
$	8.5	WA - Gas (Jan 2015)
$	1.4	OR - Gas (Nov 2014)
$	5.3	OR - Gas (April 2015)
$	22.2	pre-tax YoY impact
$	14.4	after-tax
$	0.05	2Q15 vs 2Q14 EPS

Source: UBS estimates, Company filings, FactSet

89% at Clark Fork is probably not low enough to significantly affect management's forecast for the ERM mechanism to be in the 90%/10% sharing band.

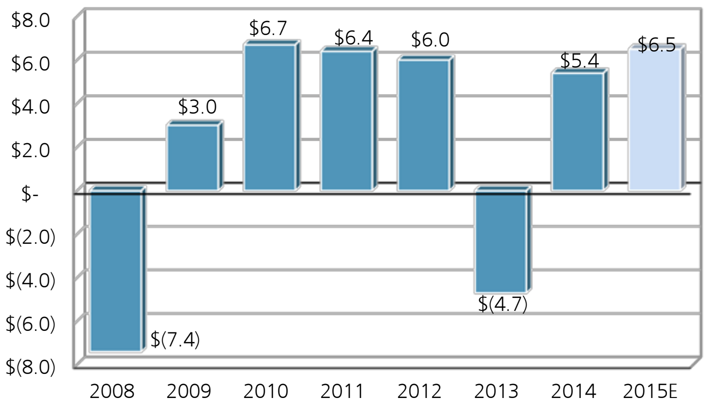
Warm weather in 1H15 caused a more rapid melt-off of snowpack vs last year, when cold temperatures kept much of the snow frozen through to Spring. As a result of this and lower precipitation levels, ERM benefits were higher than usual in 1Q15 as more hydroelectric was available for sale – and we expect lower than usual benefits in 2Q15 for the same reason. For the year, management's forecast for the ERM mechanism to be in the 90%/10% sharing band still stands (that would imply at least $5.5M of overall benefits this year). We emphasize that ERM results are heavily dependent on natural gas pricing and fleet dispatch decisions in additional to hydro conditions. We expect higher O&M as a result of lower-than-normal spending in 1H14 (timing issue). Interest is higher as a result of the $60M new debt issued in Dec 2014.

Figure 65: ERM Mechanism Earnings Impact ($M), 1Q12A-1Q15E

ERM Mechanism Earnings Impact ($M) (pretax)	2012A	2013A	2014A	2015E	Notes
1Q	4.2	3.1	1.3	5.7	Cold weax in 1Q14 (low melt). Heavy melt 1Q15.
2Q	0.9	1.0	3.6	**0.5**	Expect below normal hydro May-Aug 2015
3Q	0.8	1.9	0.4	**0.2**	Expect below normal hydro May-Aug 2015
4Q	0.1	(10.7)	0.1	**0.0**	Colstrip outage 4Q13
Yearend total	$ 6.0	$ (4.7)	$ 5.4	$ 6.5	Expect above normal hydro FY2015

Source: Company filings, UBS Estimate

Figure 66: ERM Earnings Impact, 2008-2015E



Source: Company filings, UBS Estimates

For further context, please refer to our recent notes:

5/7/15 Hydraulic Earnings Lift
3/2/15 Another Wet One?
12/22 upgrade note "Moving Back to Neutral After the Noise"
12/19/14 The 'Smid Bid': The Context for Regulated M&A

What's important for Avista?

- **In 1Q, reaffirmed 2015 guidance as mild weather is offset by higher ERM.** AVA reaffirmed 2015 guidance of $1.86-$2.06 vs UBSe $1.92 (down from prior $1.98 on mild weather) and consensus $1.98. Mild 1Q weather effect of -$0.08 (from Idaho and Oregon, which are not decoupled) is expected to be offset by +$0.06-$0.07 of benefits from the ERM, which is expected to land in the 90%/10% sharing band by the end of the year (and is not in guidance). This assumes below-normal hydro from May-Aug after higher than normal in 1Q, with overall above-normal for the full year.

- **Guidance had also assumed 4.0M of share buybacks but is impacted -$0.03** from stopping short at 2.6M shares. Instead, the company expects to issue $145M of long-term debt to maintain authorized capital structures (48.5% partial unapproved settlement in Wash, 51% in Oregon, 50% in Idaho, and 53.8% in Alaska). It also assumes normal weather for the rest of the year and 70-90 bps of regulatory lag resulting in consolidated utility ROE of 8.4%-9.0%. Our reduced (for mild weather and reduced share repurchases) 2015 estimate of $1.92 reflects the lower half of management expected utility ROE range of 8.4%-9.0%. However, our 2016-18 estimates reflect a more normalized expectation toward the middle of that range.

- **Without providing specific guidance for 2016+,** management has indicated that historically the company has issued between $25M-$50M of equity and $60M-$125M of debt annually to fund its capex programs, and that these ranges would be reasonable proxies for future years.

- **AERC's utility AEL&P contributes two-thirds of its earnings in 1H,** and the balance in 2H of each year, with 1Q15 at $0.04 and a total contribution for 2015 expected at $0.08-0.12.

- **Clark Fork stands at 73% of normal hydro condition for expected flow from April through September** (down from 101% at the 4Q call and 132% a few weeks before that). Low flow levels are of limited analytical value in isolation as the benefits of inexpensive hydropower also depend on the timing of runoff, with winter peak periods preferred. Furthermore, the ERM also depends on multiple factors including gas and purchased power pricing as well as the optimization of the entire fleet.

- **On April 15, the company received approval for a revised gas rate settlement in Oregon** with new rates effective April 16. The settlement reflects a 9.5% ROE (vs 9.9% requested) on 51% equity and an overall return on capital of 7.52%. An earlier version of the settlement (also at 9.5% ROE) had been rejected by the Oregon Commission due to concerns over various issues, including temporary revenue credits, rate design, and customer count tracking.

- **New gas rate filing in Oregon on May 1** for an $8.6M rate increase and 9.9% ROE and 50% equity. The filing also includes a proposed decoupling mechanism, whereby the company's natural gas revenues would be adjusted each month to reflect revenues based on the number of customers, rather than therm sales, with surcharges and rebates to customers in the following year.

- **On May 4, AVA announced a partial settlement of its Washington electric and gas ratecase** that was filed on February 9 based on 9.5% ROE on 48.5% equity. Capital investment plans and recovery of utility operating costs remain on the table for now. The original request was for $1.5B and $286M of elec and gas ratebase, respectively. Frequent rate filings are the norm as a result of the application of historic test years. *AVA remains long generating capacity and will not need another CT until 2020 (followed by another in 2023).*

A settlement conference for the Washington ratecase happened on July 10.

- **On June 1, filed a ratecase in Idaho** for a $13.2M electric and $3.2M gas rate increase based on 9.9% ROE on 50% equity for $767M electric and $131M gas ratebase (effective Jan 1, 2016 with a historic test year). Major capital projects in the filing include the multi-year redevelopment of the Little Falls and Nine Mile powerhouses, the replacement of IT infrastructure, and continued gas distribution line replacement. The request also includes a proposed electric and natural gas Fixed Cost Adjustment (FCA) mechanism (decoupling). Under the proposed FCA, revenues would be adjusted each month based on the number of customers, rather than kilowatt-hour and therm sales, with surcharges and rebates to customers in the following year.

- **No intermediate need for a ratecase in Alaska**, although management will continue to evaluate in the "coming months".

- **Salix updates by the end of the year.** We don't expect to hear much news about Salix at this point, with potential LNG transportation customers holding off to evaluate needs after both the drop in global oil prices and while awaiting to see how the EPA's Clean Power Plan shapes electric fuel costs and requirements. Management has discussed potential opportunities to ship containerized LNG for electric use in both Juneau as well as other parts of southeast Alaska as a conversion away from diesel. They have also discussed opportunities for marine fueling and bunkering and for transportation in Western North America.

Estimates unchanged; reducing PT $2 to $31 on lower peer P/E multiple

Figure 67: AVA 2015 Guidance and UBSe adjustments

	2015 Guidance		
	Low	High	Midpoint
Avista Utilities	$1.81	$1.95	$1.88
AERC	$0.08	$0.12	$0.10
Other	($0.03)	($0.01)	($0.02)
Consolidated	$1.86	$2.06	$1.96
UBSe adjustments			
Repurchase 2.6M shs vs 4M planned	($0.03)	($0.03)	($0.03)
Weather 1H15	($0.06)	($0.06)	($0.06)
ERM expectation	$0.06	$0.07	$0.07
UBSe adjusted guidance	$1.83	$2.04	$1.94
UBSe			***$1.92***
Consensus			***$1.97***

Source: UBS estimates, Company filings, FactSet

Figure 68: UBSe Estimates for AVA, 2013A-2017E

AVA	**2013A**	**2014A**	**2015E**	**2016E**	**2017E**	**2018E**
Segment EPS						
Avista Utilities (WA, ID, OR)	$1.81	$1.88	$1.83	$1.93	$2.04	$2.13
AERC Utility (AK)		$0.04	$0.11	$0.12	$0.12	$0.13
Ecova	$0.12					
Other	($0.08)	$0.02	($0.01)	($0.02)	($0.03)	($0.03)
UBS Estimates	**$1.85**	**$1.93**	**$1.92**	**$2.03**	**$2.13**	**$2.22**
Prior UBS estimate	$1.85	$1.93	$1.92	$2.03	$2.13	$2.22
Consensus			*$1.97*	*$2.02*	*$2.11*	
Guidance (raw)			*$1.86-$2.06*			
Guidance (adjusted)			*$1.83-$2.04*			
EPS CAGR Implied off 2014 guidance $1.87 (LT guidance 4%-5%)						*4.4%*
ROE Earned at Utility (8.4%-9.0%, including 60-70 bps reg lag)			*8.7%*	*8.7%*	*8.7%*	*8.7%*

Source: UBS estimates, Company filings, FactSet

Figure 69: AVA P/E Valuation

Avista P/E Valuation (2017E)		**Low Case**		**Base Case**			**High Case**
		Multiple	**$Mn**	**Multiple**	**$Mn**	**Valuation**	**$Mn**
				Peer	***14.7 x***		
Consolidated Net Income	$133	13.7 x	$1,826	14.7 x	$1,959	15.7 x	$2,093
Fully Diluted Outstanding Shares (2017E)			*62.6*		*62.6*		*62.6*
AVA Equity Value per Share			**$29.00**		**$31.00**		**$33.00**

Source: UBS Estimates, FactSet

Calpine (Neutral; $19 PT)

2Q appears inline, with 2015 guidance firmly intact

2015 guidance is intact – really, the focus will migrate to '2016

We project 2Q EBITDA of **$383** Mn, largely in-line with consensus at $393 Mn. Given some doubts around the outlook for IPPs amidst the latest pullback in forwards and 2015 gas/power price expectations with weak summer weather, we see even affirming existing guidance as a positive datapoint.

Primary drivers of the YoY changes include a rolloff in hedge value, offset by meaningfully higher overall expected volumes. We assume an improvement of 5TWh YoY. Further, this is the last quarter in which the sale of the Southeast 'six pack' will apply. New plant in-service and acquisitions including Deer Park/Channel expansions in Texas, the Garrison CCGT in PJM (309MW), and the Fore River acquisition from the old Boston Gen portfolio (EXC) in the ISO-NE market (720MW). Capacity payments are modestly down in PJM YoY.

- **Coal to Gas and the Drought: Uplift to Volumes?** Given the twin benefits of coal to gas switching and the drought we see a potential uplift to volumes in the medium term. We flag while a reduced footprint in the Southeast – and still a modest footprint in PJM – the big question remains whether switching accelerates in the ERCOT market place.
- **But weather could be the offset to disappointment:** In contrast to the structural tailwinds afforded in recent months, we see more disappointing weather in 2Q as limiting upside on results.

Figure 70: Comparison of YoY 1Q Results

2Q14A Adj. EBITDA ($Mn)	**$413**	
Revenue Type Walk	**UBSe**	*Notes*
Capacity Price Changes		
RA Payments (California)	-	
Non-California (PJM, etc.)	(20)	PJM Rolloff YoY, improvement in June
Energy Margin		
Hedge Position	(72)	Open hedges declining substantially (except for PJM West)
Sale of Southeast 'Six Pack'	(22)	-$43 Mn for 1H15
Deer Park & Channel	5	Began Operations in Mid-June, 2014
Garrison CC	4	1-month of In-service in Early June
Fore River	15	Closed in November, 2014
Total Uplift	**3**	
Volumetric Improvement	60	Net Increase in 1Q Generation +5 TWh, Assuming ~ Comparable @ ~$12/MWh
Net Change	**(30)**	
2Q15E Adj. EBITDA ($Mn)	**383**	
(Adjusted) Consensus	***$393***	
	$1,900-$2,100	**2015 Guidance**
	$2,055	**UBSe**
	$1,966	**Consensus**

Source: Company reports, ThomsonReuters, and UBS estimates

How are we positioning on shares?

With sparks off meaningfully of late in Texas – and now PJM as well – we understand *why* shares are trading off. We're surprised by the magnitude, albeit suspect with shares trading primarily around shifts in energy margins, we're hard pressed to 'call a bottom'. While we think PJM spark spreads are likely to 'crest' in 2015, with more plant additions contemplated in 2016-2018, headwinds on sparks in PJM. On Texas, we suspect the bottom is likely more of a ~2016 phenomenon. Similarly, California too appears to have 'topped' out for the time being, with prices continuing to decline for forward deliveries with expectations for deployment of renewables only growing. The question remains whether improved capacity prices in PJM will help shore up shares alongside meaningful further switching YoY across all markets. We see shares as cheap (albeit not significantly) vs. historic implied multiples; maintain Neutral.

Key Issues

- **Project refinancing: the latest interest expense improvement.**

  CPN announced a $1.6 billion first lien term loan transaction, with an annual interest rate of 2.75% plus LIBOR; it amortizes at a rate of 1% per year, and is set to mature in 2022. This facility will be used to retire an earlier $1.6bn loan of which had an interest of 3% plus LIBOR, subject to a LIBOR floor of 1%, and maturity of 2018. This is a positive for CPN; the company saves ~$4mn on interest expense annually, and it has also extended its debt maturity profile via this transaction.

- **Readthrough from Ormat selldown:** While we continue to see California as more challenged, we see ORA's ~11x EV/EBITDA selldown of a portion of it's geothermal portfolio per media reports in February (for 40% interest in portfolio of assets to Northland Capital), primarily in Nevada as a modestly relevant comp to CPN's Geysers portfolio in California. A key difference is Calpine's greater exposure to merchant power price trends, with the majority of its contracts seemingly indexed to Western power prices. We wouldn't doubt further Western geothermal sales of contracted assets as supportive of our modest 8x valuation multiple we apply to the entirety of its Western portfolio. We see geothermal as a clear candidate as a new renewable asset class to fall under "YieldCo" classification and premium valuations.

Updated Estimates

We have run our latest commodity deck through our estimates. Our latest revisions reflect more modest FY expectations primarily in Texas as we scale back capacity factor expectations. We are now closer to the midpoint of their 2015 Adj EBITDA guidance range of $1.9-2.1 Bn, close to consensus as well.

Figure 71: Updated CPN EBITDA Projections

Calpine Adj. EBITDA UBSe	2012	2013	2014	2015	2016	2017	2018
West	647	676	678	671	653	638	597
Texas	371	441	514	478	317	388	382
Southeast	122	102	57	48	49	47	47
North	609	611	700	749	718	691	745
Other	-	-	-	30	31	31	32
Corporate allocation	-	-	-	79	81	83	85
Total EBITDA	**1,749**	**1,830**	**1,949**	**2,055**	**1,848**	**1,879**	**1,887**
Guidance		*1800-1825*	*1915-1965*	*$1,900-$2,100*			
Street Consensus			*1,950*	*1,976*	*1,983*	*2,036*	*2,230*
Previous UBS			*1,949*	*1,984*	*1,896*	*1,930*	*2,053*

Source: Company reports and UBS estimates

We also include our latest guidance using Free Cash Flow. We emphasize that 2015 is the clear 'top' for Calpine, but suspect the near- term worries likely revolve around 2016 consensus proving to be a bit high (seemingly high by ~$100 Mn). We expect this to feature more prominently in coming months as mgmt typically provides 2016 guidance with 3Q results; this could weigh on share price performance.

Management has consistently emphasized FCF per share growth in recent times.

Figure 72: Calpine FCF Projections

Calpine FCF Analysis (UBSe)	2014	2015	2016	2017	2018	2019
UBS FCF Est. ($Mn)	**830**	**886**	**696**	**739**	**763**	**861**
Management FCF Guidance ($Mn	**800-850**	**810-1010**				
FCF per Share	**2.03**	**2.45**	**2.09**	**2.42**	**2.75**	**3.45**
Management FCF/Share Guidance	**35 - $2.10**	**$2.10-2.60**				
FCF *Growth* (YoY)	32%	21%	-15%	16%	14%	25%
CAGR off 2011 of $1.01 FCF/shr	26.1%	24.8%	15.6%	15.7%	15.4%	16.6%
FCF Yield	**12.8%**	**13.7%**	**10.8%**	**11.4%**	**11.8%**	**13.3%**
Turbine Upgrade	(20)	0	0	0	0	0
Deer Park, TX (CT Addition)	(34)	0	0	0	0	0
Channel, TX (CT Addition)	(34)	0	0	0	0	0
Garrison, DE (New PJM CCGT)	(48)	0	0	0	0	0
York CCGT (New PJM CCGT)	(100)	(100)	0	0	0	0
Other Growth		(255)				
Growth Capex	**(236)**	**(355)**	**0**	**0**	**0**	**0**
Growth & Acquisition Financing		910				
Projected Debt Amort/Sweeps	(320)	(360)	(200)	(200)	(200)	(210)
Remaining FCF	***274***	***1,337***	***496***	***539***	***563***	***651***
Asset Sales	1,573	0	0	0	0	0
Starting Cash	941	717	717	717	717	717
Ending Cash	717	717	717	717	717	717
Δ in Cash Balance	***(224)***	**-**	**-**	**-**	**-**	**-**
Deployable for Growth/Share Rep	**2,071**	**1,337**	**496**	**539**	**563**	**651**
Share Repurchase Placeholder	**(1,100)**	**(600)**	**(600)**	**(600)**	**(600)**	**(600)**
Projected Avg. Shares O/S	409	361	334	306	278	250

Source: Company reports and UBS estimates

Valuation: Reduce Price Target to $19 (from $23)

We reflect our latest target price below for shares, reflecting a decline in MtM spark spreads.

Figure 73: Calpine Valuation

All figures in US $ million except per share data	2016E EBITDAR	EV/EBITDA Multiple			Enterprise Value		
		Low	Base	High	Low	Base	High
West	653	7.0x	8.0x	9.0x	$4,570	$5,222	$5,875
Texas	317	8.0x	9.0x	10.0x	2,532	2,849	3,165
Southeast (Remaining)	17	8.0x	9.0x	10.0x	133	149	166
North	718	8.0x	9.0x	10.0x	5,745	6,463	7,181
Other	31	8.0x	9.0x	10.0x	245	276	306
Hedge Impact (Adj. for Steam,etc.)	(88)	8.0x	9.0x	10.0x	(708)	(796)	(885)
Adj. for Commodity Margin to EBITDA	113	8.0x	9.0x	10.0x	905	1,019	1,132
Total / Implied	*1,759*	*7.6x*	*8.6x*	*9.6x*	*$13,422*	*$15,182*	*$16,941*
Subtract: Net Debt						(10,479)	
Subtract: Operating Leases						(160)	
Add: NPV of NOLs						1,171	
Add: Hedge Value						88	
Add in Further Plant-Level Value	**MWs**		**$/kW**				
Remaining Southeast Portfolio:		Low	Base	High			
Auburndale Peaking Energy Center (FL)	117	$100	$200	$300	$12	$23	$35
Osprey Energy Center (FL)	599	250	350	450	150	210	270
Pine Bluff Energy Center (AR)	215	200	300	400	43	65	86
Morgan Energy Center (AL)	807	200	300	400	161	242	323
Total / Implied	1,738				*$366*	*$540*	*$713*
Subtracting out EV/EBITDA-based Southeast Portfolio					(133)	(149)	(166)
True 'Merchant' West Portfolio:							
Metcalf (CA)	605	300	400	500	182	242	303
Hermiston (OR)	635	300	400	500	191	254	318
South Point (AZ)	530	300	400	500	159	212	265
Total	1,770				*$531*	*$708*	*$885*
Subtracting out Associated EBITDA	36				(252)	(288)	(324)
York CCGT Expansion in PJM (Incremental Value @ 9x vs. Build @ 6x)					270	270	270
NPV of Equity					$4,737	$6,883	$8,852
Projected Number of Shares Outstanding (2016E)					361	361	361
Equity value per share					$13.00	$19.00	$24.00
Implied $/KW					514	582	649
FCF (pre-growth) for 2016						696	
Implied FCF Yield						10.1%	

Source: Company reports and UBS estimates

CMS Energy Corporation (Buy; $37 PT)

We see a quarterly miss at CMS, as positives from rates are muted due to weather and higher pension, investment costs.

We see a $0.06 miss for the quarter – we think consensus will revise downwards to reflect headwinds discussed in our analysis

We see 2Q15 EPS at $0.28, which is a **$0.06 miss** compared to street consensus. The weaker 2Q this year is on account of negative weather impact (vs. positive impact in 2Q14), as electricity was offset by lower gas sales in a slightly warmer May. The other headwinds this quarter include 1) -$0.03 of pension impact because of new mortality tables in effect this year; and lower discount rates used, 2) -$0.04 on account of higher investment costs (D&A, property taxes) which is a function of higher capex spend, and 3) -$0.02 from higher O&M acceleration in the quarter due to DIG outage/maintenance.

The headwinds this quarter are 1) $0.02 help from self-implementation of the $110mn rate case on June 4, and 2) $0.01 due to full benefit in 2Q from the $45mn gas rate settlement (the impact is limited because 2Q gas sales are generally muted at ~12-15% of full year volumes).

Figure 74: 2Q15 Earnings Walk

CMS Earnings Walk	EPS
2Q14A Adjusted EPS	**$0.30**
Utilities YoY	
Weather	
Return to Normal Weather	(0.02)
Current Quarter Weather Impact	(0.02)
Self implemented $110M rate increase on June 4	0.02
Settled gas ratecase for $45M on Jan 2	0.01
Pension: new mortality tables and lower discount rates	(0.03)
Retirement of debt in 2Q14 (1x cost)	0.03
Investment Costs: D&A, Property Taxes	(0.04)
Work pull ahead - most will happen in 2H15	
Higher O&M - acceleration in 2Q15 due to DIG maint	(0.02)
Lower costs and other - mostly 2H	0.02
Enterprise YoY	0.00
Interest and Other YoY	0.02
Dilution	(0.00)
2Q15 UBSe	**$0.28**
Consensus	**$0.34**
FY15 UBSe	**$1.89**
FY15 Guidance	**$1.85-1.89**

Source: Company Filings, FactSet and UBS Estimates

For additional context, please refer links to relevant recent reports below:

4/24/15 Holding the Line on 7%
4/15/15 Collecting on the Midwest Bet (MISO Auction)
4/10/15 Making up for Lost Time
3/31/15 The MISO Capacity Auction Preview: Surprise Increase in Supply (Incl. Call Transcript)
1/30/15 Under-Promising and Over-Delivering in Michigan
12/11/14 Revving Up the Opportunity in Michigan; Initiate at Buy

What's New With CMS?

- **Michigan legislation is the most relevant issue this quarter**

On July 1, Michigan Senate Energy and Technology Committee introduced legislation supporting long term integrated resource planning in the state. Under this legislation, the PSC will set parameters for integrated resource plans every four years and utilities will be required to file their IRPs for review at least every three years. The legislation should likely come through in September, with discussion lined up over the summer.

We think under Senator Mike Nof's compromise bill (SB 437-438) the number of customers opting for choice should fall over time.

More interestingly, the legislation also includes Senator Mike Nof's compromise bill (SB 437-438) which calls for consumers to elect by December 15 whether they want to continue with the utility, or chose to stay with an independent supplier. For consumers who decide to stay on choice, the independent power supplier will need to provide proof that 1) they have at least three years of capacity to back up their energy contracts, and 2) if they are importing, then they also have to provide evidence that they have the requisite transmission capacity. We expect compliance/monitoring costs around this to level the playing field somewhat by raising costs for independent suppliers.

The key here is that for customers who choose to stay with the utility by December 15th, the choice will be permanent – they can't later opt for choice. For customers who decide to elect choice, they will need to give the utility a three year heads-up notice in case they ever decide to come back in the future. People in the queue waiting to opt for choice also have to give written election – also by December 15 - whether they want to stay in the queue or if they want to come back; given these latest moves, even though the 10% choice market stands, we expect customers opting for choice to fall over time.

While there has been some speculation among investors that the recent low-price result for Zone 7 in the MISO capacity auction might incentivize some choice customers to remain under competitive service, we note that neither CMS nor DTE is likely to build the nearly 2 GW of generation needed to avoid the reserve margin shortages projected by 2020 in the recent MISO capacity forecast report.

- **Public Act 169: The rate re-design**

This will lower the cost of service to industrial and commercial customers. Industrial customers will see a 4-5% decrease in rates, when the electric rate case is implemented in December. Again we expect this to be another factor which would encourage customers to come back to the utility eventually leading to a reduction in the customers who chose alternative suppliers.

CMS self-implemented $100mn dollar electric rate case in June. An ALJ recommendation is expected in September (interestingly, right around the time as the legislation), and the final Commission order no later than December 7th.

- **Time of Use tariffs a possibility by 2017?**

  Under case No. U-17688 the PSC outlined its requirement for Consumers Energy to introduce time-of-use rates and dynamic peak pricing by Jan. 1, 2017; this may require CMS to accelerate its advanced meter program to be able to keep the timeline. According to mgmt., the company has 500 meters installed now out of a total of 1.8mn which need to be installed by

2017/18. The ToU tariffs will need to be applicable to residential customers as well as C&I.

EPS Estimates unchanged

We are largely maintaining our estimates at 7% annual earnings growth through 2017 as we assume that management will use positive developments such as better than expected sales growth and the latest DIG expansion as an opportunity to reinvest in the regulated business.

Figure 75: EPS Estimates

CMS EPS Breakdown	2013A	2014A	2015E	2016E	2017E	2018E	2019E
Consumers Electric	$1.34	$1.40	$1.43	$1.50	$1.61	$1.75	$1.88
Consumers Gas	$0.62	$0.65	$0.69	$0.72	$0.77	$0.84	$0.90
DIG Cogen Merchant Unit	$0.01	$0.02	$0.04	$0.06	$0.05	$0.03	$0.02
EnerBank	$0.07	$0.07	$0.07	$0.08	$0.09	$0.09	$0.10
Parent Drag and Other	($0.36)	($0.37)	($0.34)	($0.35)	($0.35)	($0.36)	($0.36)
Total CMS EPS UBSe	**$1.66**	**$1.77**	**$1.89**	**$2.02**	**$2.16**	**$2.36**	**$2.54**
UBSe Prior	**$1.66**	**$1.77**	**$1.89**	**$2.02**	**$2.16**	**$2.36**	
EPS growth	*7%*	*6%*	*7%*	*7%*	*7%*	*9%*	*8%*
Management Guidance - EPS Growth (%)			***5-7%***				
Total Guidance EPS	***$1.63-$1.66***	***$1.76-$1.78***	***$1.86-1.89***				
Street Consensus EPS (4/23/15)		***$1.77***	***$1.88***	***$2.01***	***$2.15***		

Source: Company Filings, FactSet and UBS Estimates

Valuation: Lower PT $1 to $37 on multiple revision

Our valuation remains based on 2017E sum-of-the-parts with probability-weighted incremental spending opportunities in Michigan from the proposed legislative reforms. As a reminder, while we include the probability-weighted contribution from ROA and RPS-related capex in our 2017 consumers EPS estimate, we have backed the ~$0.03 out from our sum-of- the-parts for consistency and clarity.

Figure 76: CMS Energy Sum-of-the-Parts Valuation

			Low Case		**Base Case**				**High Case**	
Business Segment	**Valuation Metric**	**2017**	**Valuation Multiple**	**($ MM) Value**		**Base Valuation Multiple**		**($ MM) Value**	**Valuation Multiple**	**($ MM) Value**
Regulated Entities										
					Peer Multiple	Prem/(Disc) to Peer	Base Multiple			
Consumers Electric - Base Capex	P/E	$1.57	13.7x	$5,997	14.7x	0.5x	15.2x	$6,654	16.2x	$7,092
Consumers Gas	P/E	$0.77	13.7x	$2,952	15.7x	0.0x	15.7x	$3,382	16.7x	$3,598
						Probability Factors				
			0%			75%			100%	
Incremental Opportunities	P/E	$0.38	13.2x	$0	14.2x		14.2x	$1,114	15.2x	$1,589
Regulated, Equity Value ($Mn)				**$8,949**				**$11,150**		**$12,279**
Regulated, Equity Value ($/sh)				**$32.15**				**$40.06**		**$44.12**
Unregulated and Parent Businesses										
EnerBank	P/E	$0.09	11.0x	$262		12.0x		$285	13.0x	$309
Dearborn Industrial Generation (DIG)	$kW	770	278	$214		328		$252	378	$291
Parent & Other	P/E	($0.35)	16.2x	($1,595)		15.2x		($1,496)	14.2x	($1,398)
Unregulated, Equity Drag ($Mn)				**($1,119)**				**($959)**		**($798)**
Unregulated, Equity Drag ($/Sh)				**($4.02)**				**($3.44)**		**($2.87)**
CMS Equity Value				**$7,829**				**$10,191**		**$11,481**
Fully Diluted Outstanding Shares (2017E)				278				278		278
CMS Equity Value per Share				**$28.00**				**$37.00**		**$41.00**

Source: Company Filings, FactSet and UBS Estimates

Consolidated Edison (Sell; PT $55)

Expect a penny beat vs consensus as rate changes prove to be a tailwind

We expect a penny beat with Q2 EPS at $0.62 vs street consensus at $0.61. Headwinds in 2Q15 compared to 2Q14 include a $0.06 positive impact from the multi year rate plan ($124mn for the whole year 2015) at CECONY; and another $0.02 positive impact from rate changes at O&R. We expect O&M to be a drag of a penny each at CECONY and O&R. The nonregulated energy businesses also improves a penny this quarter.

Our full year forecast is in line with consensus at $3.96 vs mgmt guidance of $3.90-$4.05.

Figure 77: ED 1Q15E vs 1Q14A Walk

2Q15 ConEd Earnings Walk	EPS
2Q14A Adjusted EPS	**$0.65**
Changes in Rate Plans	0.06
O&M: Higher gas leak survey expense & facilities reallocation	(0.01)
D&A and Property Taxes	(0.05)
Net Interest Expense: New debt interest	(0.03)
Other	-
Oil-to-Gas Conversion	0.01
Weather impact	-
Receivables Purchases in comparable quarter	(0.01)
Property Sales	-
Total CECoNY	**(0.03)**
Changes in Rate Plans	0.02
O&M	(0.01)
Other	-
Total O&R	**0.01**
Solutions (excludes MTM)	-
Development (excludes LILO)	0.01
Energy	-
Total Competitive Energy Businesses	**0.01**
Parent & Other	**(0.02)**
2Q15E Adjusted EPS	**$0.62**
2Q15 Consensus	**$0.61**
2015 Guidance	**$3.90-$4.05**
2015 UBSe	**$3.96**
2015 Consensus	**$3.96**

Subsidiary	2Q15E	2Q14
CECONY	$ 0.55	$ 0.58
O&R	0.04	0.03
Con Ed Solutions (excludes MTM)	-	-
Con Ed Development (excludes LILO)	0.04	0.03
Con Ed Energy	0.01	0.01
Parent	(0.02)	-
Total ED	**$ 0.62**	**$ 0.65**

Source: UBS Estimates, Company Filings, FactSet

For further context, please refer to our recent notes:

5/05 Consolidating Edison
2/24 ROE Risk Remains in Focus

So what's been cooking at ConEd over Q2?

REV Update: Delay in Track 2 "straw proposals"; ED submits demonstration projects

Track II proceedings will frame the quantum of opportunity available to ED under REV

We continue to track REV developments given Con Ed's exposure to the theme. In 2Q update, the NY PSC extended the deadline for the Staff to file its Track 2 "Straw Proposal" in the PSC's Reforming Energy Vision (REV) initiative (Case No. 14-M-0101) to July 28. We look for the next Track II proceedings (regulatory reform and incentives) to provide potential for incremental opportunities as well as a shift in the utility rate structure to de-risk ED through longer-term rate settlements.

Late in the quarter, NY utilities submitted demonstration projects as part of REV. Projects submitted by ED included:

1. An aggregated fleet of solar panels and storage assets to show its impact on grid services and resiliency – ED plans this in partnership with SunPower and Sunverge, where they will integrate residential behind-the-meter storage resources into the grid. The "virtual plant" in this demonstration project would have a capacity of ~1.8 MW.

2. In another demonstration project ED will partner with Opower on an energy efficiency initiative hinging on an analytics platform allowing ED to engage with customers.

3. Another project revolves around an idea called "Building Efficiency Marketplace", largely a platform allowing customer awareness and participation in ConEd's programs; which would also help users identify distributed energy resource opportunities.

We summarize below some of the other earlier, developments in REV so far, and impacts thereof:

- The NYPSC has finalized its Track I rules (Clean tech and Establishing Distributed System Platform Providers (DSPP) under its REV Docket on Feb 26: Case Docket before the NY PSC : 14-M-0101

- What does it do? Opens up the door to ConEd direct ownership in 1) Storage investments; 2) low income programs for distributed energy; and 3) pilot programs

- However, this closes the door to ConEd's direct ownership of renewables. It did seem to suggest that a third-party of ED could be involved under less stringent terms – a potential positive.

- Net-net, moving forward on REV is a positive for the state – and constructive on long-term sentiment for ConEd, but the latest developments don't appear to add anything to the incremental opportunity. Rather they firmly shut the door to ratebase ownership of many of REV's development opportunities.

The key question for Coned remains whether REV will provide some eventual upside to shareholders. While a premium ROE based on performance targets appears like a clear eventuality (akin to the UK's RIIO ratemaking process) – ratebase upside for ED appears non-existent for the time being despite initial promise.

Acquiring more wind: latest 95MW acquisition in South Dakota

More wind will help to meet ED's increased ConEd Development capex and targets. In mid-July (making this technically a 3Q update) Con Ed announced an agreement with Campbell County Wind Farm Holdings to acquire, construct and operate a 95-MW wind power project in South Dakota. The project expects to use 55 GE wind turbines, of 1.7 MW each (generate ~ 400,000 MWh annually). The project is interconnected with the Western Area Power Administration transmission system; and has a 30 year PPA with Basin Electric Power Cooperative.

NTSB investigation done; but uncertainties remain

The ball is now in the PSC's court

The NTSB concluded in early June that the Harlem explosion was caused due to failure on part of the New York City government to maintain the sewer system; but also because of a faulty plastic fusion on a ConEd pipe joint (ConEd disputes the latter point as a cause, and maintains based on its gas flow data that another crack in the pipe was the cause, rather than the joint).

Once the final report is submitted by the NTSB, it will be with the NY PSC's court, which will use NTSB inputs into its own ongoing investigations. The PSC may agree to infrastructure corrective measures which the NTSB has suggested - and it is indeed a *possibility* that the utility may not be allowed to recover costs associated with these upgrades; an eventuality which could directly impact stock value negatively. Overall, much uncertainty still remains as to financial impact to ED, until the PSC makes its final ruling – there is no timeline yet available for proceedings. We continue to expect ED to trade on news flows.

In the interim, armed with the NTSB conclusion, ED has filed a lawsuit against the city of New York claiming the govt. was negligent in constructing, repairing, maintaining and operating the infrastructure around the site of the accident.

Potential for accelerating gas main replacement capex

Potential for $200mn/yr revision to gas main replacement capex.

ED is currently spending $200Mn+ per year to replace 70 miles per year; and mgmt. said the company has a little less than 2000 miles of unprotected steal and cast iron that needs replacing. There could be an upward revision here, of as much as another $200mn/yr revision. This is currently in a docket with the PSC. We expect mgmt. can elect to upgrade much of this via rate plans, following the PSEG example (PSEG filed a $1.6bn plan for NJBPU approval of accelerated five-year gas modernization plan and related recovery rider; $320mn per year is for replacement of cast iron and unprotected steel gas mains). ED may submit a vision plan in December.

We think this further ties into our thesis of a shifting focus across the utility sector, with managements keen to expand investment in gas infrastructure. The distribution bill at its lowest level in years provides meaningful headroom; along with support of an increasingly concern regulatory environment. Supporting these are expectations in the govt's Quadrennial Energy Review, that ~ $270 billion are needed in the US to replace the ~9% of gas distribution infrastructure which is made of leak-prone cast iron and bare steel.

Solutions still under strategic review – no further updates

Mgmt. confirmed no further updates under the strategic review of retail electric supply business which it announced over 1Q15 results review. We reiterate our estimate that the segment could be worth ~$32mn, and accretive to earnings (based on a conservative value of $200/customer for its ~158,600 customer base).

We highlight possible upside as existing retail sales channels are valuable to distributed solar developers, and this one also carries a valuable brand name (Coned Solution) as well. While a total exit appears likely after mgmts. announcement, we have been writing about the possibility for this business to be scaled back from its current national focus, levering its NY home-town advantage and balance sheet to compete for customers (71% of sales are currently from outside NY).

O&R still waiting on final approval of the joint proposal

Mgmt. confirmed there are no updates on this front, with ED still waiting for final approval for O&R for a 9% ROE; 48% equity ratio ask (which is the same as the CECONY deal).

Unchanged Estimates

We show below our earnings estimates for ED vs. guidance and consensus. From 2016 onward we assume that the Retail operation is sold, with no further losses. We are below consensus for 2017 when we assume ROEs at ~8.8%, which is 40bps below the 2014 ROE. As noted above, CECONY has recently opened settlement discussions on their electric rate case (Docket: C-15-E-0050).

Figure 78: Consolidated Edison EPS Estimates

Consolidated Edison EPS Ests.	2014E	2015E	2016E	2017E	2018E
Consolidated Edison of New York	$3.61	$3.71	$3.71	$3.87	$3.96
Orange & Rockland	$0.20	$0.23	$0.24	$0.23	$0.24
Competitive Businesses:					
Con Ed Solutions (Retail)	($0.02)	($0.01)	$0.00	$0.00	$0.00
Con Ed Energy (Wholesale)	$0.00	$0.00	$0.00	$0.00	$0.00
Con Ed Development (Solar)	$0.06	$0.08	$0.12	$0.14	$0.16
Other	$0.04	($0.05)	($0.15)	($0.28)	($0.31)
Consolidated (diluted shares)	$3.89	$3.96	$3.92	$3.96	$4.05
% Growth		*2%*	*-1%*	*1%*	*2%*
Prior estimates		$3.95	$3.91	$3.96	$4.01
Guidance		$3.90-$4.05			
UBSe on basic sharecount	$3.91	$3.98	$3.94	$3.98	
Consensus	$3.89	$3.96	$4.00	$4.14	$4.31

Source: Company filings, FactSet, and UBS estimates

Valuation: Maintain Sell Rating at $55 PT

We value ED on 2017E, applying a 5% discount to shares given the ROE risk.

Figure 79: 2017 ConEd Discounted Valuation

Consolidated Edison Valuation			
Regulated 2017 P/E Multiple		*14.7x*	
	Low Case	Base Case	High Case
2017 EPS	$ 3.96	$ 3.96	$ 3.96
x P/E Multiple	14.7x	14.7x	14.7x
Discount	-10%	-5%	5%
Assumed CECONY ROE	8.8%	8.8%	8.8%
Valuation	$52.00	$55.00	$61.00

Source: Company filings, FactSet, and UBS estimates

Dominion Energy (Buy; $77 PT)

An uneventful quarter as the company begins a 9-year rate freeze and prepares to construct Cove Point and the Atlantic Coast Pipeline.

We expect D to report **$0.70** EPS for 2Q15, closer to the midpoint of guidance $0.65-$0.75 than consensus of $0.75. Weather for the quarter was slightly better than normal with a warm 2H of June. Utility O&M should increase 1%-2% offset by weather normalized sales growth of about 1%. At merchant gen, there were no material unplanned outages, although guidance embeds a $90M EBIT uplift for the absence of planned maintenance that occurred in 2Q14. Furthermore, while power pricing remains slightly below where guidance was issued in February, the Millstone is 88% hedged for 2015 and Fairless (unhedged) is in a constrained location with less impact.

Expect a miss vs consensus but in-line vs guidance.

Figure 80: D 2Q15E v 2Q14A Earnings Walk

Last year vs Guidance	2Q14 ABS	2Q15 Low	2Q15 High	2Q15 Mid
VEPCO (weather normalized)				
Elec Dist	217	195	220	208
Elec Trans	141	155	175	165
Utility Gen	370	380	415	398
D&A	(217)	(230)	(250)	(240)
Regulated Gas (weather normalized)				
Gas Dist	73	65	85	75
Gas Trans	200	185	210	198
D&A	(58)	(55)	(75)	(65)
Merchant Gen	52	130	150	140
D&A	(24)	(30)	(35)	(33)
Dominion Retail	12	10	15	13
D&A	(1)	-	-	-
Interest	(226)	(225)	(215)	(220)
Corp & Other	(15)	(35)	(25)	(30)
Income Taxes	(163)	(175)	(205)	(190)
Income Tax Rate	31%	32%	31%	31%
Operating Earnings after-tax	361	370	465	418
Shares	584	594	592	593
EPS	**0.62**	**0.62**	**0.79**	**0.70**
EPS Guidance Range				*0.65-0.75*

2Q14A	**0.62**
2Q15 vs normal	0.00
VEPCO (weather normalized)	
Elec Dist	(0.01)
Elec Trans	0.02
Utility Gen	0.03
D&A	(0.02)
Regulated Gas (weather normalized)	
Gas Dist	0.00
Gas Trans	(0.00)
D&A	(0.01)
Merchant Gen	0.09
D&A	(0.01)
Dominion Retail	0.00
D&A	0.00
Interest	0.01
Corp & Other	(0.02)
Dilution	(0.01)
2Q15E	**0.70**
Consensus	***0.75***
2Q15 Guidance	***0.65-0.75***
2015 Guidance	***3.50-3.85***

Source: UBS Estimates, Company Filings

For additional context, please refer links to relevant recent reports below:

5/5/15 Revving Up a Cash Flow Engine
3/11/15 A Royal Endowment
2/26/15 Dropping in on the MLP
2/10/15 King of the Hill
11/21/14 Seeing is Believing
11/10/14 initiation report on Dominion Midstream Partners LP "Classic GP/MLP Story with an LNG Twist"
11/3/14 Baking in Piping Hot Growth

What's new with Dominion:

- **We don't expect any change to annual guidance** of $3.50-$3.85 vs UBSe $3.59 and consensus $3.69. Guidance for the 2Q and FY15 does not include any additional income from producer farmout activity, which had added $0.04 in 1Q15 and for which management has guided to

roughly ~$450M-$500M of pretax income potential from 2015-2020 (about $0.10/year although the timing is not likely to be smoothly divided over the five year period).

- **VEPCO filed its 2015 Integrated Resource Plan (IRP) on July 1** for the period 2016-2030. Instead of the usual "preferred plan", the filing includes four options listed below to comply with anticipated EPA Clean Power Plan rules. All plans include the completion of the Brunswick and Greensville CCGTs by 2016 and 2019, respectively, as well as 400 MW of utility-owned regulated solar by 2020 and another 400 MW of non-utility solar by 2017. These plans are considered by management to be a starting point for further discussion about the preferred path forward given uncertainty over national and state-level carbon and clean power goals, with a more definitive plan expected next year with the 2016 IRP.
  - Plan A: Solar, characterized by a high concentration of utility-scale solar resources (4,000 MW by 2040);
  - Plan B: Co-fire, including using natural gas to partially fire eight Dominion-owned coal powered units to reduce carbon intensity;
  - Plan C: Nuclear, designed to include construction and operation of North Anna Unit 3, providing an additional 1,453 MW of nuclear-powered generation at the Company's North Anna Power Station; and
  - Plan D: Wind, including significant on-shore (247 MW) and offshore (2,016 MW) wind development.
- **VEPCO began what is effectively a nine-year rate freeze under enabling legislation in Feb 2015 that suspends biennial rate review periods for five years through the end of 2019. We see ROEs in the low-to-mid teens following cost reductions.** Accelerated spending in 2013/14 should keep ROE low for the 2015 biennial rate review (filed on March 31) while setting up potential for lower O&M and earnings beats later. While fuel and purchased power remain subject to annual review under a separate fuel rider, we also see expiring PPAs as possible justification for new self-build generation within ratebase under rate riders should this option be deemed beneficial under annual IRPs.
  - Under the Feb 2015 legislation, the latest biennial review is limited solely to a determination of VEPCO's actual earned ROE during the combined 2013-2014 test period and whether any refunds are due to customers. The company filed a 10.13% ROE vs 10.00% authorized; well within the +/- 70 bps sharing band, so no refund would be due if accepted. The low ROE is in part due to accelerated timing of expenses into 2014, lending itself to further tailwinds at VEPCO into 2015 (we see upside to earned ROEs here). We note that while the 2015 review may result in a refund, no rate decrease is possible and no additional refunds can be made until the next review in 2022 (for the 2020-2021 period). And no rate decreases are possible until they have two consecutive biennial reviews with overearnings in both – the earliest that could happen would be the 2024 review, with any possible rate reduction in late-2024. Note that the utility may still file a ratecase during the transition period, although the law

specifically makes the company responsible for bearing the risk of "…severe weather events and natural disasters, as well as the risk of asset impairments related to the early retirement of any generation facilities due to the implementation of the Clean Power Plan regulations."

- **Expect a construction update for Cove Point,** which had 80% of engineering work complete as of the 1Q call, with equipment procurement on schedule. Also expect an update for the **Atlantic Coast Pipeline** and 1.5 dTh/day Header project, for which a FERC CPCN application is expected to be filed in September as surveying and engineering work continues. The Supply Header is expected to provide feedstock for the proposed Atlantic Coast Pipeline.

- **Expect updates for the Greenville County proposed 1,585-MW, $1.3B CCGT,** planned to be in service in 2019. On July 1, the company filed for a certificate of public necessity and convenience (CPCN). The plant is expected to be one of the largest combined cycle gas plants in North America and would be built under a rate rider if approved. Also, as of the 1Q call, the 1,368-MW Brunswick County CCGT was 60% complete and still expected to be in service mid-2016.

- **VEPCO is proceeding with its 400 MW goal for regulated solar in Virginia** (legislation allows for 500 MW). The 400-MW program is planned to cost ~$700M, adding ~$0.07 to 2016 estimates. Hearings on the 20-MW Remington project are expected in 3Q. By comparison, SO pursued a ~500 MW program at GA Power at the commission's request.

- **New merchant solar announcements expected.** The acquisitions of the 20-MW Richland and 20-MW Alamo merchant facilities were announced in April and May, respectively, bringing the total merchant solar portfolio up to 384 MW. D plans to grow to 450 MW by yearend 2015 and to 625 MW by yearend 2016. Previously, the company has guided to $2B of contracted solar investment through 2016. This is in addition to the prev announced plan to invest $700M to build 400 MW of ratebased utility scale solar in VA. On the 1Q call, management reiterated its plan to eventually sell these assets, possibly in stages, initially with a partial sale into a joint venture followed by a total sale after the ITC and other tax restrictions expire. We think this could include sales to a YieldCo entity, emphasizing accretion relative to the very the limited EPS contribution these assets provide after ITC capture.

- **Solar YieldCo announcement could be key.** <u>Mgmt has previously stated that they would probably announce in late summer (likely at its annual September update) a partner for its YieldCo JV structure</u>, which is likely to start with a 20-30% stake in its targeted ~650MW solar biz (~$1 Bn total capital by end of 2016). We suspect the solar biz will be gradually sold down as the tax repatriation period comes to a close, making the JV a perfect ROFO sell-down complement to the winning YieldCo (we see top 3 YieldCos as the clear candidates seeing mgmt as keen to only deal with the premium currencies in the sector). We suspect TERP or NYLD remain the top candidates for the structure; a 'promote' (or premium initial sale price) is likely to reflect the benefit of the subsequent ROFO arrangements.

- **NGLs: We continue to expect little impact from lower global oil prices** on Blue Racer's natural gas liquids processing business. 80% of the business is fixed-fee under 15-20 year contracts with little remaining exposure among the remaining 20% that is partially exposed to spreads. We also note that most of Blue Racer's feedstock comes from the sweet spot of the Utica, perhaps the most prolific shale in the US, with over 500 producing wells and another ~500 drilled and awaiting D's expansion of takeaway and processing capacity. The large backlog shows no signs of abating anytime soon.
- **Where to next in the midstream expansion? Florida.** We see the potential for the Atlantic Coast Pipeline (ACP) to be expanded to stretch into Florida to reach Duke's service territory in Northern Florida. Passage through Georgia could yet involve SO, but we flag the latest SCANA asset acquisition includes pipe that is already jurisdictional to the state, expediting any prospective regulatory process. Bottom line, we're incrementally more confident this pipeline will not only be expanded, but will indeed be extended as well. This could well be needed to serve the incremental gas needs from future projected load growth and contemplated new gas generation build at DEF.
- **More M&A coming? Lots of accretive midstream opportunities.** Management has suggested that it could see further opportunities for acquisitions in the midstream segment leveraging the DM currency. Specifically, it sees an opportunity to swap assets for a share in the DM business itself, enabling any prospective shareholder to benefit from continued growth at this business as well as limiting needs to tap equity capital markets further.
- **Growing the dividend *and* earnings too?** Given the robust cash flow profile of IDR payments under its GP structure with its MLP, and the low maintenance capex associated with these assets, management appears exceptionally bullish on the outlook. Notably, management suggested that it could even increase its payout to over 100% and still grow its earnings at its targeted range beyond the in-service of Cove Point.

Figure 81: Dominion's Merchant Solar Asset Portfolio – Expect 450 MW & 625 MW by Yearend 2015 & 2016

Solar Project	Seller	Capacity (MW)	Location	Deal Status	Completion Date	In-service Date	Estimated Transaction Value ($MM)	ISOs
Pavant Solar Project	Juwi Solar Inc	50	UT	Completed	11/10/2014	2015	NA	NA
Catalina Solar 2 Cottonwood	EDF Renewable Energy Inc	18 24	CA	Pending	1H15	2015	175	
West Antelope Solar Park	Canadian Solar Inc.	20	CA	Completed	11/24/2014	11/24/2014	NA	
CID Solar	EDF Renewable Energy Inc	20	CA	Completed	12/11/2014	4Q14	70	
Mulberry Farm Site Selmer Farm Site	Strata Solar LLC	16 16	TN	Completed	5/7/2014	Late 2014	2	NA
Kansas Solar Project Kent South Old River One Solar Project RE Adams East Solar Facility RE Camelot Solar Facility RE Columbia Two Solar	Recurrent Energy	20 20 20 19 45 15	CA	Completed	3/31/2014	Late 2014 / Early 2015	50	CAISO
Alamo Solar	E.ON North America	20	CA	Completed	5/1/2015	2Q15		CAISO
Somers Solar Facility	Kyocera Corp	5	CT	Completed	10/22/2013	2013	NA	New England
Richland Solar Center	HelioSage Energy	20	GA	Completed	4/15/2015	2H15	NA	
Azalea Solar Power Facility	Investor Group	8	GA	Completed	2/28/2013	2013	NA	NA
Indy Solar I Indy Solar II Indy Solar III	Sunrise Energy Ventures, LLC	10 10 9	IN IN IN	Completed	7/22/2013	2013 2013 2013	NA	MISO
Total		**384**						

Source: Company filings, SNL and UBS estimates

Estimates reduced slightly for lower power deck; reduce PT $2 to $77 on lower peer P/E multiple

Our price target remains derived via business by business SOTP using 2017E P/E and EV/EBITDA, with a DCF approach for Dominion Midstream. We continue to see a positive skew to our EPS at VEPCO, suggesting the potential for positive revisions over time.

Figure 82: Dominion Resources EBITDA and EPS, UBSe vs Guidance vs Consensus 2014A-2019E

Estimates by Segment (EBITDA) using ABS		UBS								
	EBITDA	EBITDA	FY15 EBITDA Guidance			UBSe				
VEPCO	2014A	2014A	Low	High	2015 Mid	2015E	2016E	2017E	2018E	2019E
Electric Distribution	905	905	895	925	910	914	1,020	1,087	1,140	1,192
Electric Transmission	588	588	660	680	670	671	800	906	1,006	1,102
Utility Generation	1,726	1,726	1,855	1,930	1,893	1,893	2,046	2,095	2,116	2,137
Virginia Power - Corp Adjusted	-	-	-	-	-	-	-	-	-	-
VEPCO DD&A	(878)	(877)	(960)	(985)	(973)	(972)	(1,103)	(1,120)	(1,162)	(1,233)
VEPCO Adjusted EBIT	**2,341**	**2,341**	**2,450**	**2,550**	**2,500**	**2,505**	**2,763**	**2,969**	**3,101**	**3,199**
Regulated Gas Ops										
Gas Distribution	327	327	325	350	338	338	377	415	453	490
Gas Transmission (DTI, CP Import)	1,044	1,044	1,015	1,090	1,053	1,076	1,199	1,216	1,326	1,333
Cove Point Export, Prod Svcs, Other		(0)				(25)	87	177	565	549
Dominion Midstream LP Minority Interest (after ta:	(7)	(7)				(18)	(30)	(48)	(77)	(147)
LP Minority Interest % (UBSe)	31.5%	31.5%				31.2%	38.7%	45.0%	50.8%	58.2%
GP Distributions (after tax)	-	-				0	3	16	37	81
Gas Operations DD&A	(241)	(241)	(230)	(250)	(240)	(240)	(260)	(280)	(300)	(312)
Total Regulated Gas EBIT	**1,124**	**1,124**	**1,110**	**1,190**	**1,150**	**1,133**	**1,376**	**1,497**	**2,004**	**1,995**
Merchant Generation EBITDA	459	459	665	745	705	612	506	585	672	722
Merchant DD&A	(98)	(98)	(140)	(145)	(143)	(143)	(140)	(137)	(134)	(132)
Total Merchant Generation EBIT	**361**	**361**	**525**	**600**	**563**	**470**	**366**	**448**	**537**	**590**
Previous Merchant Generation EBIT						*458*	*402*	*482*	*572*	*625*
Dominion Retail EBITDA	70	70	50	70	60	60	60	61	61	62
Retail DD&A	(2)	(2)	-	(5)	(3)	(3)	(3)	(3)	(3)	(3)
Total Dominion Retail EBIT	**68**	**68**	**50**	**65**	**58**	**57**	**57**	**58**	**58**	**59**
Corp & Other	(49)	(49)	(80)	(75)	(78)	(69)	(9)	(54)	(93)	(80)
Total Adjust EBIT	**3,845**	**3,844**	**4,055**	**4,330**	**4,193**	**4,096**	**4,553**	**4,917**	**5,607**	**5,762**
Interest expense	907	907	910	890	900	895	956	1,008	1,175	1,134
Income Taxes	925	925	1,070	1,100	1,085	1,060	1,195	1,304	1,486	1,573
Non-controlling Interests	9	9	15	20	18	-	-	-	-	-
Net Income	**2,003**	**2,003**	**2,060**	**2,320**	**2,190**	**2,140**	**2,402**	**2,605**	**2,946**	**3,055**
Shares Outstanding	585	585	597	595	596	595	619	636	643	639
EPS	**3.43**	**3.43**	**3.45**	**3.90**	**3.67**	**3.60**	**3.88**	**4.09**	**4.58**	**4.78**
Previous UBS Estimates						3.59	3.91	4.14	4.62	4.82
Guidance of 6%-7% growth off 2014 3.48 weax adj base; 5%-6% from '14-'17 and 7%-9% from '17-'20	3.48		3.50	3.85	3.68	3.67	3.87	4.09	4.41	4.77
CAGR of UBS Estimates, 2014-2017 and 2018-2019								**5.6%**		**8.1%**
2014-2019										**6.5%**
Consensus						3.68	3.88	4.08	4.54	5.15

Source: UBS Estimates, Company Filings, FactSet

Figure 83: Dominion Resources Sum of the Parts Valuation on 2017E -> PT $77

Dominion (D) Sum of the Parts Analysis - UBSe							
	2017E Adj. EBITDA	EV/EBITDA			Enterprise Value		
		Low	Base	High	Low	Base	High
Dominion Merchant Generation	436	8.0x	9.0x	10.0x	3,487	3,923	4,359
Hedge Value	(7)	8.0x	9.0x	10.0x	(54)	(61)	(68)
Dominion Energy (DTI & Iroquois)	1,035	10.0x	11.0x	12.0x	10,348	11,383	12,417
Dominion Midstream Partners Minority Interest	(60)	10.0x	11.0x	12.0x	(597)	(656)	(716)
Dominion Retail	61	4.0x	5.0x	6.0x	243	303	364
Total / Implied	1,465	9.2x	10.2x	11.2x	13,427	14,892	16,357
Implied value of Merchant & Retail vs. Street 'consensus' per mgmt						6.65	11.00
Phase 1 MLP Cove Point Preferred, CGT, Blue Racer, ACP and Cove Point Export through 2020							
			Ownership %	LP Shares	Price		
Dominion Midstream (DM) LP units			68.8%	64	$ 41.11	1,809	*$2.84*
LP Distribution Equity Value NPV of existing assets not yet dropped in DM valuation						765	*$1.20*
GP Distribution Equity Value NPV						2,275	*$3.57*
PV of Compensation for Dropdowns from DM						3,764	*$5.91*
Total Equity Value of MLP Phase 1						8,613	*$13.53*
Phase 2 (DTI, Dom E Ohio, Iroquois) 2018+							
Phase 1 & 2 discounted cash flows from all dropdowns (after tax leakage)			$ 24,342				
Minus Phase 1 NPV GP + LP Distributions from Cove Point, Blue Racer Dropdown			$ (8,613)				
Minus DTI, LDCs, & Iroquois Equity Value (before MLP dropdown)			$ (11,004)				
MLP Phase 2 Incremental Uplift to SOP			$ 4,725	probability	80%	3,780	*$5.94*
Total Incremental Equity Value of MLP to SOP						12,393	
add: NPV of 2016 cash flows from Cove Pt Import						191	
less Total Dominion net debt						(24,249)	
netting VEPCO-associated debt						9,992	
netting VEPCO debt allocated to HoldCo						2,560	
netting MLP related debt (Cove Pt Import/Blue Racer-Only)						1,925	
netting Gas LDC-associated debt						1,098	
Net Energy/Generation Debt						(8,675)	
Total Corporate Debt Drag vs. Street 'consensus' per mgmt (per share)						(13.63)	(9.00)
add: NPV of Merchant Generation Hedges						69	
Dominion Energy, MLP, Merchant Generation, and Retail					$ 17,405	$ 18,870	$ 23,186
Current Number of Shares outstanding					636	636	636
Dominion Energy, MLP, Merchant Generation, and Retail per Share					$ 27.35	$ 29.65	$ 36.43
	Peer P/E Multiple 14.7x		Premium 1.0x				
Dominion Delivery	2017 Net Income		P/E Multiple				
Electric	422	14.7x	15.7x	16.7x	6,211	6,633	7,056
Transmission	321	15.7x	16.7x	17.7x	5,040	5,361	5,682
Dominion Generation-Utility	961	14.7x	15.7x	16.7x	14,120	15,081	16,042
Total VEPCO Net Income	1,704	14.9x	15.9x	16.9x	25,371	27,075	28,780
VEPCO per Share (vs. Mgmt est.)						42.54	41.00
Gas Distribution LDCs							
East Ohio	171	15.7x	16.7x	17.7x	2,679	2,849	3,020
Hope Gas	10	15.7x	16.7x	17.7x	160	171	181
Total Gas Distribution Net Income	181	15.7x	16.7x	17.7x	2,839	3,020	3,201
Current Number of Shares outstanding					636	636	636
Dominion Regulated Utilities SOP Value ($/sh)					$ 44.33	$ 47.29	$ 50.25
Total Remaining Implied for Energy Biz vs. Mgmt 'Range' of Value						41	45-55
Total Equity Value per Share					$ 71.68	$ 76.94	$ 86.68

Source: UBS Estimates, Company Filings, FactSet

DTE Energy Co. (Buy; $93 PT)

Latest MI energy bill has reignited shares but still underperforming YTD (stark contrast to CMS)

YoY growth in 2Q driven by the unregulated businesses but the core regulated utilities will assume the driver's seat for the summer, benefitting from self-implemented rates.

We forecast DTE reporting adjusted 2Q15 EPS of **$0.85**, versus consensus of $0.87. The utilities face weather headwinds (above-average in 2Q14 and below-average this quarter) and face some degree of regulator lag before new rates became effective July 1st (self-implementation). Due to the rate relief we see growth coming in the third quarter with the combination of stronger weather and new rates. The unregulated businesses compensate for the quarterly weakness with trading having recorded a $10Mn loss in 2Q14 versus our assumption of ~flat performance for FY15. The timing of corporate tax booking can skew results unpredictably with $25Mn net expense recorded in 1Q15 versus FY15 guidance of a ($50)-($46) net loss.

Figure 84: FE 2Q15 Earnings Walk

EPS	DTE Energy Earnings Walk
$0.73	2Q14A EPS
0.12	Unregulated Businesses
0.04	P&I: Higher volumes at REF sites; lumpy quarterly earnings
0.07	Trading: Lost $10Mn in 2Q14; assume ~flat operating EPS
0.01	Midstream: Continued investment in gathering system
(0.04)	Regulated Utilities
(0.02)	2Q14 Weather (+$3Mn Detroit Edison & +$1Mn MichCon)
(0.01)	2Q15 Weather: Cooler than normal; 50% decline in June CDDs
0.01	Weather normalized load growth 0.0%-0.5% in 2015
(0.02)	Depreciation, property taxes, and other
0.00	O&M (reinvestment) / lean: Weighted toward 4Q
0.05	Corporate & Other
0.06	Corp & other: FY15 ~$48Mn guidance; $25Mn 1Q15 | $18Mn 2Q14
(0.01)	Dilution - issuing $200M in 2015, issued at various times through the pension plan.
$0.85	1Q15E UBS
$0.87	2Q15E Consensus
$4.66	2015E UBS
$4.64	2015E Consensus
4.48-4.72	2015 Guidance

Source: Company Filings, FactSet, and UBS Estimates

For additional context, please refer links to relevant recent reports below:

4/27/15 A Tiger Roars Into Spring

4/10/15 CMS Energy: Making Up for Lost Time

2/17/15 Michigan's Engine to Drive Growth

12/12/14 Doubling Down on Detroit; Upgrade to Buy

9/12/14 Managing Michigan's Coal Transition & the MISO Upside Story

What's new with DTE?

- **Michigan Senate Committee proposes energy bill which could be passed this Fall:** As expected, the Michigan Senate Energy and Technology Committee as led by State Senator Nofs introduced energy legislation on July 1 that would likely end electric choice as it is today and replace current renewable standards with a broader clean energy standard. Two separate bills (SB 437 and 438) call for integrated resource planning (IRP) to replace the current renewable energy and energy efficiency standards by 2019. The effect of this would be to place more responsibility on the Public Service Commission (MPSC) for the establishment of both clean energy goals and reserve planning, with IRP parameters set every four years and IRPs filed by the utilities every three years. Hearings are set to begin later this month, in time to review the bills through the Summer recess that goes through Labor Day. Once the legislature is back in session in September, we then expect a version of the legislation to progress out of the Committee within a few days for full consideration by the Senate and House. We expect that process to move rapidly if Nofs is successful in garnering widespread agreement for any resulting compromise draft.

Senator Nofs bill looks good for CMS and DTE and would likely end customer choice through tougher rules.

Timing appears slated for late Summer full decision

Hearings will run all summer on bills through committees

- **Legislation would shift capacity burden to suppliers, leveling the playing field:** On electric choice, the bills include a three-year notice of return to service for customers opting to remain with a competitive supplier, and a commission-determined planning reserve margin that will be established for competitive suppliers (also known as the "fair choice" provision). Early press reports indicate that a pro-competition group, Energy Choice Now, has already stated that Nofs' bill would "end electric choice" and that Alternative Energy Suppliers [would be held] to much higher standards than the utilities and the bill ultimately requires multiple unachievable goals." It's unclear whether this is rhetoric or reality at this point from our perspective. We see 2016/17 as the critical year for the Michigan (Zone 7) to see MISO capacity prices clear significantly higher than adjacent markets (notably the Covert CCGT unit will leave MISO for PJM next year).

- **Clearing the path for new generation:** So as to not lose sign of the trees within the forest, the benefit for the utilities is that a bill would likely reduce the level of commercial/industrial choice customers by 80%-90% (to only 1%-2% of load) by reducing the financial incentives to remain a non-utility customer. <u>This is the primary condition needed to justify the expected construction of nearly 2 GW of new gas-fired generation by CMS and DTE that would be required to avoid reserve margin shortfalls projected by 2020 in the recent MISO capacity forecast report</u>.

Concerns regarding a lack of action earlier in May/June drove relative underperformance but shares of CMS and DTE have been improved recently.

- **Staff recommends 10% ROE in electric rate case:** As expected, DTE self-implemented a $190Mn interim electric rate increase on July 1st (subject to refund) as part of its $370Mn base rate increase request. On May 22nd the PSC Staff recommended a $174Mn rate increase which was premised on a 10% ROE vs DTE's request for a 10.75% ROE (10.50% currently authorized in 2011 case); much of the revenue delta appears driven by the lower ROE. Following the release of the Staff position shares declined to their most severe underperformance of 2015 (5% relative underperformance) but have reversed much of these earlier losses. The next steps to watch for are briefs by July 28th and an ALJ's PD is targeted for October 8th with a decision in Michigan required by December 21st (12 months after original filing). Docket: U-17767

DTE requested a 10.75% ROE and the Staff recommended a 10.0% ROE in its pending electric rate case.

- **Shifting the rates to improve business competitiveness:** In a separate docket, the PSC ruled on the rate design issue in the attempt to incentivize further economic development for heavy usage industrial customers. The decision specifically resulted in a 5% reduction for primary customers and a 4% increase for residential customers, less extreme of a shift than previously contemplated by some discussions. The impact of the rate design are largely similar to those for CMS' utility Consumers Energy. Case No. U-17689

- **Waiting for approval to accelerate gas distribution spending:** Management is still awaiting a final order for the Expanded Infrastructure Recovery Mechanism (IRM) Filing in 1H15 and a decision is expected in 2H15 for a surcharge potentially January 2016. On June 15th the PSC approved the settlement for the typical annual renewal of the IRM with the surcharge increase effective July 1st. Docket: U-16999

Expansion of Vector depends largely now on future expansion of NEXUS (and Rover).

- **FERC provides NEXUS update – Still on track for 4Q15 formal filing:** The FERC recently provided an update on its review of the NEXUS 1.5 bcf/d pipeline and the Commission is still providing comments on the draft environmental reports submitted by management in June in order to prepare the environmental impact statement (EIS). Comment letters continue to focus primarily on the route and possible alternatives based upon wildlife and other potential environmental impact concerns. The project sponsors still plan to submit a formal application in early 4Q15. Based upon the current timeline in-service is scheduled for November 2017. Earlier this year, the NEXUS pipeline wrapped up a supplemental open season for additional receipt points from Texas Eastern. Once the project is in service, there remains the possibility to expand another 0.5 bcf/d through looping and compression as the market requires. Docket: PF15-10

- **Enbridge considers NEXUS a "strategic project" but will they invest?:** We are still awaiting a final decision on whether Enbridge will retain its 1/3rd stake in the NEXUS project and Enbridge management commented in May that it views the project as "very strategic" while touting the benefits but has not made a firm commitment publicly as of yet. As a reminder, should Enbridge drop out, DTE may have the possibility of upsizing its investment by ~ $300M to a 50% stake.

- **Vector pipeline expansion depends on NEXUS expansion:** Vector also wrapped up an open season earlier this year and signed long-term 15+ year contracts with both NEXUS and the Rover pipeline, effectively replacing expiring contracts (no expansion but also no earnings degradation). However, there was not enough shipper interest at that time to justify adding compression at the pipe currently. A future expansion remains possible should NEXUS increase its own capacity. We look to see if there are any incremental updates on Vector or Millennium on the call.

- **The Millennium pipeline is currently being expanded** to 1.0-1.3 bcf/d as east-west spreads remain wide and New England remains constrained. The expansion is seen as a critical route to getting Marcellus gas to Eastern gas utilities and management expects to announce new details once they are through finalizing commercial terms of the contracts as they work through the terms from the successful open season. A further expansion to 1.5-1.8 bcf/d is possible though looping and/or parallel pipe, but not likely to see anything before 2017.

- **Another utility moving to capitalize on utility-scale solar before 2017:** DTE recently issued a build and construct RFP for a utility-scale solar (between 5MW-100MW) in its service territory to be online by YE16 to take advantage of the ITC step-down. Responses are due by August 19th

Valuation: Maintain Price Target

We continue to use a 2017E sum-of-the-parts methodology and are maintaining our $93 Price Target.

Figure 85: Updated DTE Sum-of-the-Parts

Business Segment	Prob	Valuation Metric	2017	Low Case Valuation Multiple	($s MM) Value	Base Case Valuation Multiple	($s MM) Value	High Case Valuation Multiple	($s MM) Value
Regulated						Regulated Peer Multiple	14.7x		
DTE Electric		P/E	$3.46	14.2x	$9,087	15.2x	$9,727	16.2x	$10,367
Incremental ROA, Renewables Capex	75%	P/E	$0.25	14.2x		15.2x	701	16.2x	997
Incremental 2020-2024 New Generation	75%	P/E	$0.32	14.2x		15.2x	893	16.2x	1,269
DTE Gas		P/E	$0.99	14.7x	2,684	15.7x	2,867	16.7x	3,050
Regulated, Equity Value					**$11,771**		**$14,188**		**$15,682**
Unregulated Business									
Power Projects		EV/EBITDA	$263	9.0x	$2,366	10.0x	$2,629	11.0x	$2,892
Midstream		EV/EBITDA	$199	11.0x	2,185	12.0x	2,384	13.0x	2,582
Incremental Midstream Opportunities	25%	EV/EBITDA	$8	11.0x		12.0x	92	13.0x	397
Trading		EV/EBITDA	$9	4.0x	36	5.0x	45	6.0x	54
Parent & Other Overhead		EV/EBITDA	$36	9.0x	324	10.0x	360	11.0x	396
Less: Parent Debt, Net (2017E)					(2,535)		(2,535)		(2,535)
Unregulated, Equity Value					**$2,376**		**$2,975**		**$3,787**
DTE Equity Value					**$14,148**		**$17,163**		**$19,469**
Fully Diluted Outstanding Shares (2017E)					185		185		185
DTE Equity Value per Share without incremental opportunities					*$77.00*		*$83.88*		*$90.59*
DTE Equity Value per Share including incremental opportunities at probability					**$77.00**		**$93.00**		**$105.00**

Source: Company Filings, FactSet, and UBS Estimates

Duke Energy (Neutral; $79 PT)

Expect a miss on continued poor hydro in Brazil and the absence of 1x tax benefits last year. Could see 2015 guidance adjusted downward as a result and we've reduced our 2015-2018 estimates a nickel.

We estimate that Duke will report a wide miss for 2Q15 at **$0.93** vs consensus $1.03. Expect the miss to be driven by milder weather, the absence of a 1x 0.05 state tax settlement in 2Q14, the absence of a 1x $0.07 tax benefit in Chile, and -0.05 continued poor Brazilian hydro results from their short power position there due to the drought. We also expect -$0.02 of FX rate impact against the Brazilian Real during the quarter and another -$0.02 impact on National Methanol due to continued low oil pricing (loose Brent correlation) vs last year. The removal of merchant power earnings early in the quarter had a positive year-over-year effect as most of the earnings last year were generated from renewables, which are expected to grow $40M this year (full year earnings). Additionally, we expect $0.03 of accretion from the $1.5B share repurchase program initiated in early April. Nuclear outage levelization reduces -$0.03 but this impact is expected to moderate in 2H15. Weather-normalized load growth and wholesale earnings are expected to grow $0.06 combined, offset by -0.02 of year-over-year weather comps despite a favorably hot last two weeks of June.

We are inclined to think management may decide to reduce FY15 guidance by at least a nickel (to $4.50-$4.70) as guidance currently assumes normal Brazilian hydro for the year for a net $0.05 improvement.

Figure 86: DUK 2Q15 Earnings Walk

DUK 2Q15 Earnings Walk	
$1.11	**2Q14A Adj. EPS**
	Regulated Utilities
(0.04)	Reversal of Weather in Comparable Quarter
0.02	Weather vs normal in 2Q15 - had a heat wave in late June in the Carolinas
(0.01)	O&M growing at about 1/4 the rate of load
0.03	Load Growth (~1.0%, with 100 bps = ~$0.10 eps)
0.03	Wholesale Growth: ~$0.10 EPS Inc. Expected YoY FY15
(0.03)	Nuclear Outage Levelization expect to moderate in 2H
(0.05)	absence of 0.05 favorable 2Q14 state tax settlement
(0.02)	Depreciation, property taxes, interest, and other
	Commercial Power: Excluding Midwest Gen
-	Reversal of Midwest Gen
0.01	Renewables: $40Mn incremental income YoY FY15
0.03	Accretion from use of Proceeds: Deal closed in April
	International and Other
(0.02)	Brazil: Impact of F/X (0.02-0.03 annualized for 10% change).
(0.07)	Brazil: Reversal of Chile Tax Benefit
(0.05)	Brazil: Impact of Hydro (short power thru 2015 but expect to moderate in 2H)
(0.02)	NMC: Correlation to Brent Crude $0.02 for every $10/bbl
0.00	Parent & other - income taxes
$0.93	**2Q15E EPS UBSe**
$1.03	***2Q15 Consensus***
$4.66	***2015 UBSe***
$4.67	***2015 Consensus***
$4.55-$4.75	***2015 Guidance***

Source: Company Filings, FactSet and UBS Estimates

We estimate the trailing 12 months EPS at $4.43 including our $0.93 estimate for 2Q15, well below guidance for the year of $4.55-$4.75. However, accretion from

share buybacks should boost EPS another nickel in 2H. Brazil hydro issues began in 3Q14 and we could see a moderated (i.e., positive year over year comp) in 2H15, although we concede that the company's drought-driven short position there had not improved much through 2Q15. The impact on National Methanol also began last year with the collapse of Brent crude prices in 3Q14, thus we should see a moderate to improved year-over year comp in 2H15 here as well. While the Brazilian Real has continued to devalue, we see a more moderate comp in 2H for this too. All-in-all, we are inclined to think management may decide to reduce FY15 guidance by at least a nickel (to $4.50-$4.70) as guidance currently assumes normal Brazilian hydro for the year for a net $0.05 improvement (excluding the Chilean tax benefit in 2Q14).

Reducing our estimates: We've reduced our 2015-2018 estimates a nickel for continued trouble in Brazil as well as more conservative assumptions on O&M and other costs.

For additional context, please refer links to relevant recent reports below:

5/5/15 Even More Cash Coming
2/26/15 Cashing in and Beefing Up
1/5/15 More Than Just an Oil Slick
11/6/14 Put Up Your Dukes

What's New With Duke Energy?:

- **Ash excavation work at both the Riverbend plant site** (retired) in NC and the W.S. Lee plant in SC began in May. These are two of the first five ash remediation sites that were targeted for excavation to fully lined facilities by 2019 within the North Carolina Coal Ash Management Act of 2014. Remediation of the Asheville Plant site has been continuing for years.

- **Also in May, the company announced the retirement of the 376-MW Asheville coal plant in NC** in the next 4-5 years, with plans to replace the facility with a 650-MW natural gas-fired power plant (~$750mn); and a transmission substation near Campobello, SC, and a 40-mile, 230 kV line (~$320mn). "Most" of this capex is incremental to DUK's February 5-year capital plan that called for $41.75B of total capex from 2015E-2019E, including $2.95B of "discretionary" spend (a minority portion is considered part of the discretionary bucket). This could add as much as $0.05-$0.08 EPS incremental to prior expectations by 2019 if approved. It is our understanding that the project is receiving early support from legislators and environmental groups in the Western side of the state.

- **DUK plans to file a new grid modernization plan in Indiana by the end of the year** after the first one was rejected by the Indiana Utility Regulatory Commission (IURC) on May 8. The original $1.9B plan was filed under Indiana's SB 560, which allows the IURC to approve riders for a "transmission, distribution, and storage system improvement charge (TDSIC)". Of the plan, we believe that about ~$300M was found questionable for eligibility under the law, with the company expected to continue to pursue approvals for these projects under normal ratemaking procedures rather than the rider process. The remaining ~$1.6B would then begin construction later than planned in 2016 if ultimately approved under a rider.

- **Securitization legislation for Crystal River 3 was passed.** With the passage of SB 288/HB 7109 in June**,** DUK plans to file a specific plan to address the mechanics of securitization by July 21. The law allows the PSC up to 120 days to consider this filing, with a vote no later than November 2015. If all goes according to plan, the securitization bonds could be issued with a recovery charge in place as early as February 2016.
  - In advance of final passage, DUK had also filed for PSC approval of a $170.3M electric base rate increase for 20 years beginning Jan 2016 based on the amortization of a $1.3B regulatory asset (Docket # 150148-EI). This filing essentially established the prudency of the asset with a non-securitized recovery method in case securitization is blocked for any reason.
- **NC legislators are considering House Bill 332 to freeze the state Renewable Portfolio Standard at the current 6%.** The bill passed the House and has been sent to the Senate for consideration, where press reports indicate strong support. Otherwise, existing law would increase the RPS to 12.5% incrementally through 2021. DUK has expressed support for a collaborative process similar to the one in South Carolina.
- **More Solar in Florida:** In Duke's latest ten-year plan in Florida it includes up-to 35MW of ratebased solar by 2018 and up to 500MW over the ten-year horizon.

Guidance assumes a return to normal hydro in Brazil

Below we highlight the various opportunities DUK has identified for the 2016-17 period to bring earnings up to 4%-6% despite the "dip" in 2015. Among the notable points are $7.4B of ratebase growth guidance in these two years alone (<u>we now exclude $0.12 EPS from the reinstatement of $1.45B of ratebase from Crystal River 3 in 2017 as securitization in lieu looks likely</u>), AFUDC from the construction of the Atlantic Coast Pipeline, and retail load growth of 1% annually that adds about $0.10 EPS per year. We calculate nearly $0.75/sh of opportunity to meet 4%-6% guidance that implies $0.40-$0.80 of improvement from 2015-2017. <u>However, the critical factor in realizing the full potential of these opportunities is maintaining earned ROEs through rate lag mitigation and cost control</u>. The guidance also assumes a return to normal hydro conditions in Brazil as well.

The critical factor in realizing the full potential of these opportunities is maintaining earned ROEs through rate lag mitigation and cost control. We've also assumed no further deterioration of earnings from the International segment.

Figure 87: Potential 2016-2017 EPS Upside Growth Opportunities vs Guidance

Potential 2016-2017 EPS Growth Opportunities vs Guidance		
Utility Growth Capex	Capex 2016-17 ($B)	EPS Potential
New Generation	$1.9	0.15
NCEMPA Asset Purchase	$1.2	0.10
Environmental *	$1.3	0.11
Major Nuclear	$0.3	0.03
Customer Additions	$1.1	0.09
SB560 Infrastructure Investments	$0.5	0.04
Grid Modernization	$0.6	0.05
Other T&D	$1.8	0.14
Depreciation & other	($1.2)	(0.10)
Total ratebase growth $8.9B @ 0.08 per $1B	$7.4	0.60
Retail load growth 1% annually @ 0.10 per 1%		0.20
O&M growth at less than load growth (about 1/4)		(0.05)
Wholesale Contracts (guided 0.01-0.03 growth in 2016 & 17)		0.04
Atlantic Coast Pipeline (AFUDCe on ~$900M 2016-17)		0.07
Elimination of $90M Commercial Power Genco EPS in 2016+		(0.13)
Commercial renewables $1B-$2B @ ~13% ROE		0.14
UBSe Contango Brent Crude curve effect on NMC		0.02
DUK management assumptions BRL/USD FX curve		(0.06)
UBSe BRL/USD FX curve vs conservative management assumptions		0.03
Effect of Brazil power rationing (UBSe)		(0.15)
Debt repayment $1.4B @ 4%		0.05
No equity through 2017 (no dilution)		-
Potential 2016-2017 EPS growth opportunities		$0.75
Sensitivity to 100 bps ROE		+/- $0.40
Guidance for EPS growth 2015-2017		
Midpoint guidance for 2015		$4.66
Guidance range for 2017 based on 4%-6% off 2013 $4.33		$5.06 - $5.46
Guided 4%-6% EPS growth 2016-2017		$0.40 - $0.80

* Includes coal ash basin remediation costs of ~$1.3B from '15-'19 for Dan River, Riverbend, Sutton, Asheville, and W.S. Lee (SC), another $1.3B for wastewater treament conversions, $250M for 316b compliance, and $300M for MATS compliance

Source: Company filings, UBS estimates

EPS Estimates reduced for Brazil Hydro & O&M

We present our updated EPS estimates below, incorporating the accelerated share buyback program. Our estimates are reduced a nickel for continued trouble with Brazil hydro as well as more conservative assumptions for O&M and other costs. We see 2015 as under pressure from International despite various offsets as noted above, including higher Genco earnings (prior to sale) and an earlier stock buyback (benefitting ~$0.04).

Figure 88: EPS Estimates reduced -$0.05

DUK EPS	2013A	2014E	2015E	2016E	2017E	2018E
UBSe	$4.35	$4.55	$4.60	$4.95	$5.20	$5.38
Prior UBSe	$4.35	$4.55	$4.66	$5.00	$5.27	$5.43
Consensus			$4.67	$4.93	$5.18	$5.43
Guidance			$4.55-$4.75			
UBSe 2013-2017 CAGR					4.7%	
LT Guidance: Grow EPS 4%-6% through 2017 off 2013 guidance $4.33						
4% growth	$4.33	$4.50	$4.68	$4.87	$5.06	$5.26
5% growth	$4.33	$4.54	$4.77	$5.01	$5.26	$5.52
6% growth	$4.33	$4.58	$4.86	$5.15	$5.46	$5.79

Source: Company Filings, FactSet and UBS Estimates

Figure 89: DUK Price Target reduced to $79 (from $84)

Duke Energy Valuation: P/E Derived on 2017 EPS					
Downside Case		***Base Case***		***Upside Case***	
Valuation		**Price Target**		**Valuation**	
2017 EPS	$5.20	2017 EPS	$5.20	2017 EPS	$5.20
P/E Multiple	14.1x	P/E Multiple	14.6x	P/E Multiple	15.1x
Premium	-5%	Premium	5%	Premium	10.0%
Value	**$69.00**	**Value**	**$79.00**	**Value**	**$86.00**

Source: Company Filings, FactSet and UBS Estimates

Dynegy (Buy; $37 PT)

We look for a better YoY comparison with Dynegy reporting 2Q15E adjusted EBITDA of **$142Mn**, but shy of Street ($244Mn) as the first quarter with its latest offset the lower power price environment. While weather was milder across the Midwest footprint YoY, we see improvements in the IPH portfolio and GasCo sparks could well add incrementally. The primary YoY factor remains the loss of the ConEd capacity contract for the independence unit, which was significantly above market

Look for meaningful improvement YoY, but shy of Street, mostly on back of DUK & ECP deals

Having had a full quarter, we estimate the ECP portfolio added ~$106 Mn of EBITDA during its first full quarter, the majority of the overall company, and out of a total $582 Mn we project inclusive of synergies for the year.

Figure 90: DYN 2Q YoY Estimate

Dynegy ($Mn)	2Q15E	2Q14E	2QE YoY	1Q15A	1Q14A	1QA YoY	Notes
Consensus EBITDA	*$244*						
Adj. EBITDA UBSe	142	38	*104*	85	152	*(67)*	
Corp & Other	(31)	(28)	*(3)*	(29)	(24)	*(5)*	*Similar trend of ~$30Mn*
IPH	10	-	*10*	22	30	*(8)*	*Outages and low pricing drove weak 2Q14 results*
CoalCo	9	8	*1*	10	42	*(32)*	*Limited transmission outages; fairly comparable periods YoY*
GasCo	48	58	*(10)*	82	104	*(22)*	*Capacity (PJM +ve) & RA pricing +along with Independence / Ontelaunee better given Basis w/o ConEd Contract + Black Mountain loss*
ECP & Duke	106	-	*106*	-	-	-	*Transaction closed April 1st*

Source: Company reports and UBS estimates

For additional context, please refer links to relevant recent reports below:

6/26/2015: Gassing Up the Portfolio [Analyst Day Takeaways]
4/15/15 Collecting on the Midwest Bid (MISO Auction)
2/25/15 Defining the Value Proposition
1/19/15 Another Round of the Waiting Game
11/7/15 Opportunities Abound: Sourcing Additional Upside

What's New With Dynegy?:

Understanding the nuance behind the capacity buildup into guidance

Among the key points of clarity from management was an explanation that roughly $200Mn/yr of its $1.3 Bn/yr average EBITDA from '16-'18 was from uncleared/uncommitted MISO capacity as well as the forthcoming PJM Capacity Performance uplift.

We see Street as potentially interpreting this as a relative disappointment vs. consensus for '15 & '16 of $1.3 Bn supposedly without these uplifts.

We have previously estimated the uplift from the PJM transition auctions as being upwards of ~$160 Mn for the 2016/17 period, limited for 2017/18, and likely a further +$100 Mn for the 2018/19 auction YoY (suggesting +$50 Mn from).

Bottom line, we see DYN's assumption of $200 Mn/yr from uncleared capacity as likely primarily derived from MISO (mgmt was able to sell ~$100 Mn in 2015, suggesting upwards of $70+ Mn/yr to what is already hedged on forward estimates in 2016-18 assuming stable prices, a very conservative base). While we

understand including this incremental uplift was the subject of some debate going into the Analyst Day among mgmt, we see uncertainty around exactly how this uplift is derived as lingering with investors, beyond just the latest weak commodity environment. We expect at least the mystery around the PJM uplift to be 'realized' in coming weeks with the transition auctions and full auctions planned in late July into early August

What are we awaiting now? Key for 2Q will be disclosures for PJM

Expect details on MISO and PJM composition of it's '16-'18 guidance

Following substantial uncertainty in exactly what was communicated at its Analyst Day, management intends to provide a meaningful update of what exact MWs were cleared in each of the Capacity Performance transitional auctions by the time it reports (it could yet release individual releases at the time of each auction as well). We suspect this will help clarify the comments at the time of its $1.3 Bn guidance figure, suggesting there was a limited albeit conservative amount reflected for CP transition and base auction uplifts.

- **So what exactly did they say?** The most significant new disclosure at the Analyst Day was the 2016-2018E adjusted EBITDA guidance of $3,900Mn-$4,900Mn ($1,300-$1,633Mn per year simple average). This was a bit light of our expectations and we still see some downside given the decline in the forward curves since the May 13 mark-to-market. With this in mind, despite lowering our estimates we still forecast $3.9Bn of EBITDA over the 2016-2018E period as our 2018E assumes the contribution of Capacity Performance at $160/MW-Day compared with more conservative assumptions from Dynegy.

- **What's the shape of the guidance? Roughly <u>flat</u> EBITDA through the 2016-2018 period.** As part of its $3.9Bn baseline guidance, management emphasizes that improvement YoY was less than $100 Mn per year, given the wide number of puts and takes in the forecast period. We emphasize that this specifically mutes our expectations for a more meaningful jump in 2018. Dynegy's leading platform gives it an advantage in further power consolidation.

- **Synergies to keep coming:** <u>Although management increased its transaction synergy target to $130Mn from $100Mn announced in April</u>, we expect more synergies to come. The majority of the synergies to date have been related to fuel and transportation related gross margin savings along with procurement indicating that there are still operational savings ripe for use. As Dynegy gains more experience operating the combined fleet **we expect the latest version of PRIDE will provide another material update, potentially with 3Q/EEI**. The fuel/input savings are not yet fully baked and it appears clear that fuel blending savings are coming in the near-term. The strong synergies naturally have an immediate benefit for valuation but the speed and consistency with which Dynegy has been able to extract costs from its acquisitions provides investors with the highest confidence in the management team. Not only does Dynegy set the benchmark with which investors compare other M&A transactions but its ability to extract more costs than peers often allows it to outbid competitors while still making deals accretive.

- **DYN will not clear all capacity in CP auction.** Mgmt cautioned that while it was constructive on the uplift from CP (embedding ~$100 Mn in benefit in its forward guidance), it would clear only a portion of its fleet. For instance, it appears the Zimmer coal plant would not qualify for the CP benefits.

We expect to hear much more to this point in coming periods. While some managements have proven categorical about their fleets holding up through CP qualification, we suspect this will become a necessary disclosure from many management teams given the potential for a sharp price differential between products.

Other Updates

- **More Illinois Basin too?** Mgmt emphasized it remained in conversations with Murray Energy/Foresight coal to employ greater Illinois Basin at its Illinois portfolio. Specifically, it was seeking to install a conveyor belt (as long as 6-miles) to make the plant effectively mine-mouth to the Illinois plant. The plant has a scrubber in place already and seemingly could already blend in quantities of ILB. Meanwhile, there is further discussion around blending additional quantities of ILB at the IPH portfolio's Newton plant, which has its scrubber installation contemplated for later this decade. There remains the potential for either the coal industry or the state outright to fund associated costs with pending retrofit (scrubber) costs, which remains a key ongoing development project.

  Bottom line, we perceive growing sentiment from the coal segment on prospects for ILB coal to finally gain back share from volumes lost to PRB. We see this as a net-net positive to mgmt, which is able to pin each supplier off against each other.

Building out More Capacity

- **Berks Hollow:** Management disclosed it had recently acquired from LS Power the rights to develop the Berks Hollow development site, adjacent to its existing Ontelaunee CCGT facility. While we see little likelihood for the company to actually pursue site development at this point in time, we see the acquisition as at least limiting the potential for any *other* party from developing a new site near DYN's existing plant. The plant would be 750MW, likely around the $1,000 to 1,200/kW range from our read from mgmt's comments.

- **Re-activating mothballed capacity at EEI plant in Southern Illinois.** Management also indicated it would bring back 235 MW of seasonal peaking capacity at its EEI plant (IPH portfolio) for a total cost of $1 Mn. The plant would have multiple dispatch opportunities into MISO, TVA, and the Kentucky Utilities (KU) service territory.

Portfolio

Divestment of California remains in the cards – just not yet

California sale still coming: We continue to await an update on the fate of the (small) California portfolio following finalization of the pending gas distribution and transmission rate design case for PG&E. It's Moss Landing 1&2 plant resides behind PG&E's gas distribution network, leaving it significantly exposed to inflationary tariffs due to enhanced gas safety spending in the state. Mgmt had previously concluded that uncertainty around the tariff made the divestment of this portfolio unattainable, particularly seeing this 1GW CCGT asset as the jewel of the portfolio. Management's latest guidance emphasizes resolution by late this year. Management commented in the media last week it was continuing this sales process; we see a sufficiently active California market such that a transaction should be ultimately achievable

- **Texas remains our focus:** We continue to see DYN as strategically positioned to eventually expand into the state – likely via an asset contribution or outright acquisition *by* the TCEH creditors as part of a post-restructuring move. Bottom line, we see this as among the most critical angles to the story – both in terms of potential synergies (both portfolios burn significant quantities of PRB with the same rail shippers).

We still look for an eventual deal with EFH

- **The Illinois Deal:** Among the biggest wildcards for Dynegy remains the outcome of ongoing efforts in Illinois to effectively save the nuclear industry in the state- or not. We emphasize that should Exelon opt to retire the Clinton nuclear plant (although we would not expect such a decision immediately), this would significantly impact the outlook for both capacity and energy in the MISO footprint. We see a retirement decision by EXC's other plants as more likely, such as Quad Cities. Even the shutdown of this plant in PJM, on the border with Iowa, would be viewed positively. We suspect an initial shutdown decision could be reached by ~September (although some recovery potential would remain).

Financials

- **Capital allocation biased towards share repurchase and paying down debt:** Over the next three years Dynegy estimates it will have $1.1-$2Bn of excess capital for allocation; this is pre $75Mn preferred dividend and loan principal repayment but post IPH carve-out (cash will remain in the IPH box, presumably to support debt paydown/refinancing as well as Newton scrubber discussed below). The uprates and performance related spending is expected to account for $150Mn which still leaves over $400Mn of annual funds available. In our valuation we effectively assume a debt paydown but management listed share repurchases as a higher priority. Dynegy did state that a longer-term goal would be to "migrate" towards a 'BB' credit rating but this did not appear to be a near-term focus. Management sees the net debt/EBITDA improving to 4.4x from 4.9x over the next few years in its base case although the FFO/Debt metric would decline 90bp to 10.3% over the period. The concept of paying a common dividend was also effectively ruled out for now as well. **Similar to synergies above, we anticipate an update with 3Q/EEI following the PJM auction datapoints.**

Buyback announcement could come as early as 3Q.

- **Environmental liabilities largely unchanged with addition of new assets primary moving piece:** Over the next three years Dynegy has ~$50Mn of annual environmental capex for [1] 316(b), [2] ELG; and [3] CCR but the spending is concentrated in 2018. 316(b) is barely material ($60Mn) and the spending is clustered post 2018. The increase in ELG capex is driven by the recently purchased assets and the largest category is CCR which is a bit challenging to forecast until management conducts its needed site analyses. Novel projects like the beneficial reuse of coal ash could significantly reduce the capex requirements for CCR in the future and the third party fly ash mill at Duck Creek slated to be completed next year is a prime example.

Beneficial reuse of CCB could free-up significant cash in the future.

- **IPH on firmer footing:** Management characterized itself as pleased with the outlook for the non-recourse IPH subsidiary which management sees improving to a 5.5x net debt / EBITDA and 9.5% FFO / Debt over the next three year period, a significantly rosier outlook compared with recent history. In February Dynegy disclosed that it negotiated the EPC deal for the Newton Scrubber and indications continue to point towards IPH staying within Dynegy although management does not appear to be in any rush to lock itself into a position

"Outlook for IPH has materially improved through 2018"

with the next 7.0% Series H $300Mn Senior Notes not due until 2018 ($264Mn fair value) and the 6.3% Series I $250Mn Senior Notes maturing in 2020 ($208Mn fair value). After these two lumpy maturities the runway is clear for more than a decade.

Updated EBITDA Estimates

We include our latest updates to forward estimates, down slightly further from our recent Analyst Day MtM. We caution that management guidance stated forward estimates wouldn't necessarily move much between years, suggesting there may be too much inter-year swings between our 2017 and 2018 estimates.

Figure 91: Pro-Forma Forward EBITDA Estimates for DYN

Dynegy EBITDA Breakdown (UBSe)	2014A	2015E	2016E	2017E	2018E	2019E
Midwest	114	186	194	177	215	264
West	52	65	65	35	41	41
Northeast	187	165	146	141	164	160
Illinois Power Holdings	79	123	78	107	150	154
Duke Midwest	0	216	320	294	405	428
Energy Capital Partners	0	240	350	393	414	351
PRIDE Reloaded & Other Synergies	0	118	165	205	205	205
Consolidated G&A and Other	(85)	(125)	(130)	(130)	(130)	(130)
Recurring Adjusted EBITDA	**347**	**987**	**1,187**	**1,222**	**1,464**	**1,474**
Previous	***347***	***1,046***	***1,226***	***1,252***	***1,462***	***1,471***
Growth	59%	184%	20%	3%	20%	1%
Consensus (7/8/15)	**$364**	**$1,009**	**$1,291**	**$1,283**		
Mgmt Guidance: Adj EBITDA	**$300-$350**	**$825-$1,025**	**$1,300**	**$1,300**	**$1,300**	
Capital Spending	**-$160**	**-$285**				
Cash Interest	**-$145**	**-$425**				
Other Cash Impacts	**$15**	**-$15**				
Free Cash Flows	**$10-$60**	**$100-$300**	**~$500**	**~$500**	**~$500**	

Source: Company reports and USB estimates

Moving Down SOP Target to $37/sh from $40/sh

Reflecting the latest shifts in commodities, we are shifting down our target a further $3/sh. We had previously updated our valuation methodology with the Analyst Day to reflect a 9x EV/EBITDA multiple on the bulk of the portfolio.

Figure 92: Dynegy - $37 PT reflects lower commodity prices

Dynegy Inc - 2017E	EBITDA	EV / EBITDA Multiples Low	Base	High	Low	Base	High
Legacy Dynegy	354	8.0x	9.0x	10.0x	$2,829	$3,182	$3,536
Illinois Power Holdings (IPH)	107	7.0x	8.0x	9.0x	$746	$853	$960
Duke Midwest	294	8.0x	9.0x	10.0x	$2,353	$2,647	$2,941
EquiPower	393	8.0x	9.0x	10.0x	$3,145	$3,538	$3,931
Less: West Peaking & Brayton Point	(26)	8.0x	9.0x	10.0x	($211)	($237)	($264)
Plus: Capacity Performance	79	0.0x	**0.0x**	3.0x	$0	$0	$236
Synergies, Corp. Overhead, & Other	75	8.0x	9.0x	10.0x	$600	$675	$750
Total Unregulated EV	**1,275**	**7.4x**	**8.4x**	**9.5x**	**$9,462**	**$10,658**	**$12,090**
Net Debt							
Dynegy Inc.					$6,386	$6,386	$6,386
Illinois Power Holdings (IPH)					$825	$825	$825
Plus: NPV NOL Shield & West Peaking					($240)	($537)	($587)
Cash and 2015/2016 FCF					($1,039)	($1,371)	($1,718)
Total Net Debt					**$5,932**	**$5,303**	**$4,906**
Net Debt / Adjusted EBITDA					*5.x*	*4.4x*	*4.1x*
Total Equity Value					**$3,530**	**$5,355**	**$7,184**
Implied FCF Yield					*10%*	*6%*	*5%*
Shares Outstanding					143	143	143
Dynegy Valuation					**$25.00**	**$37.00**	**$50.00**
Upside/(Downside)					**-15%**	**25%**	**69%**
Price Target Gross EV/EBITDA Multiple					*7.7x*	*8.7x*	*9.9x*
Current Price Implied Gross EV/EBITDA Multiple					*7.9x*	*7.4x*	*7.1x*

Source: Company reports and UBS estimates

Edison International (Neutral; PT $66)

In-line quarter and we do not expect 2015 guidance until a final decision in the GRC and the post-decision booking of tax benefits and cost savings remain a significant wildcard (to the upside in our opinion).

We expect an **in-line 2Q at $0.79 vs consensus $0.76** and last year's $1.07, which was boosted by a combination of cost savings and tax benefits. As we saw in 1Q, we expect the company to continue to reserve for tax benefits that are likely to be clawed back in the final rate order. Cost savings from last year are expected to become part of the new revenue requirement as well, with the utility having reduced its rate request for 2015 in January to only $34.4M from the originally filed $156.7M in Nov 2013. The company has also proposed sharing about $20M ($0.04 EPS) of incremental benefits in 2015 as well. In our breakout table below, we build our quarterly projections based on post-GRC ratebase expectations and then add the effects of not having a final GRC order yet (we assume a $34.4M annualized drag), the continued impact of cost savings, and parent expenses. We assume a 3Q rate order and that the company keeps another $0.12 of post-order cost savings in 4Q (largely offsetting parent expense). We expect another $0.05 of energy efficiency earnings in 4Q as well. Management does not intend to initiate 2015 guidance until the final order is released. We project a range of $3.55-$3.60 vs UBSe and consensus $3.60.

We do not expect the settlement to be reopened, but the increased workload for Darling and Dudney could be partially responsible for continued delays for the GRC.

On the timing of the GRC PD and final order, we've assumed 3Q largely as a result of considering that (1) The last GRC had a complete record in 1Q and a final decision in 4Q. This GRC also has a completed record in 1Q, but ALJ Darling has a second ALJ (Dudney) helping her this year; and (2) ALJ Darling is also reviewing the SONGs OII, which has been extended through July 31 (could easily be extended again) and remains open pending consideration of ex-parte violations, penalties, and The Utility Reform Network (TURN)'s request to reopen the settlement that was approved last November. As noted below, we do not expect the settlement to be reopened, but the increased workload for Darling and Dudley could be partially responsible for continued delays for the GRC.

Figure 93: EIX 1Q15E vs 1Q14A Walk

	Ex-SONGS EPS Distribution				
Year	Q1	Q2	Q3	Q4	Total
2009	24%	24%	34%	18%	
2010	24%	18%	42%	17%	
Average	24%	21%	38%	17%	
	UBSe 2015 Estimate Distribution				
Ratebase	0.86	0.75	1.36	0.63	3.59
Income tax benefit/(exp)	-	-	-	-	-
GRC delay unrecovered costs with catchup	(0.02)	(0.02)	0.03	-	-
2014 cost savings with GRC clawback	0.09	0.09	(0.18)	-	-
2015 cost savings after GRC order	-	-	-	0.12	0.12
Energy efficiency	-	-	-	0.05	0.05
Parent & other	(0.03)	(0.03)	(0.02)	(0.05)	(0.13)
UBSe 2015 (basic)	0.90	0.79	1.19	0.75	3.63
UBSe 2015 (diluted)	0.89	0.79	1.18	0.74	3.60
Consensus		*0.76*	*1.19*	*0.78*	*3.60*
Expected Core EPS Guidance					3.55-3.65

Source: UBS Estimates, Company Filings

For additional context, please refer links to relevant recent reports below:

6/25/15 TURNing Its Back on the SONGS Deal
6/9/15 Preparing for the California Rate Design Shift
6/5/15 Calming Concerns on California
4/29/15 Time for a Tune Up Over SONGS
2/26/15 Cutting into the 2015 Reset
1/14/15 Charging up the Utility EV Infra Opportunity
10/30/14 High Growth Story Now Fully Valued
10/15/14 3Q14 Earnings Playbook: Trading Tips for Turbulent Times
10/24/14 How Low Could Transmission ROEs Go?
8/1/14 Up, Up, and Away (in 2014)
3/30/14 Focused on the Core Strategy
3/24/14 Hitting the High Notes With SONGS

What's new with EIX:

- **No timing for a GRC decision (but we assume 3Q).** While the last GRC took 9 months to render a Proposed Decision (PD) with the same ALJ, it's difficult to predict the wait this time around, with the case paused for 2-3 months last year after Presiding Commissioner Peevey was replaced by Commissioner Peterman after becoming embroiled in ex-parte violations (and yearend retirement). Considering the original yearend 2014 target and that ALJ Darling has ALJ Dudley also working on the case, our rough estimate for a PD could be as early as 3Q15. We do not expect any decision before the SONGS OII is wrapped up in May (also by ALJ Darling). Furthermore, a commissioner's involvement in the proceedings is typically back-end loaded, so we would not anticipate a significant incremental delay to get Commissioner Peterman up to speed.

- **A Distributed Resource Plan was filed on July 1** under OIR R.14-08-013 as part of compliance with AB 327, the law that also implements re-design of residential rates, tier collapse, fixed charges, and net metering. While the plan gives the first real glimpse of \$1.8B-\$3.1B of potential distribution system capex through 2020, although firm spending plans won't materialize until the next GRC filing that should come toward the end of 2016 (for 2018 rates). See below for details.

- **Surprise rejection of SONGS settlement from consumer advocacy group TURN.** In a surprise turn on June 23rd, The Utility Reform Network (TURN) called for California regulators to set aside their previous approval of the 2014 multi-party settlement (including TURN) of costs associated with the decision to permanently shut the San Onofre Nuclear Generating Station (SONGS) in favor of a litigated outcome. This request was included in a filing within the SONGS Order Instituting Investigation (OII) examining the impact of alleged ex-parte reporting violations on behalf of ex-President Peevey. This is a surprise reversal of prior unambiguous opposition to a reopening of the settlement. Our discussions indicate that the change of heart is due to a notable shift in public perception regarding the credibility and reputation of the California Public Utility Commission (CPUC) over the past several months around the agency and settlement specifically.

    - **Rejection by TURN does not require CPUC to reopen the settlement.** It is our understanding the CPUC is not required to go back and reverse its previous approval of the settlement with one party calling for a resumption of the litigated process. We suspect the commission will see little practical evidence to suggest that the commission's prior decision was necessarily

unreasonable. More tangibly, we see this move as adding to pressure to approve a fine against EIX for ex-parte communications within the SONGS settlement process. Furthermore, in discussing with multiple parties, we still see the outcome of the settlement as supported on its merits and a good deal for consumers. As such, we emphasize that even if the docket is reopened, the risks poised to EIX are more modest.

  - **It's about public perception for TURN, but ORA still opposes a reopening.** In our discussion with the Office of Ratepayer Advocates (ORA), they continued to unambiguously oppose a reopening of the settlement, but also made clear that they intend to pursue $648M of penalties for undisclosed ex-parte violations within the Order Instituting Investigation (OII). We see a more likely penalty limited to $10M-$20M based on a $50k/day limit. The Alliance for Nuclear Responsibility has requested a $35M fine in their OII filing.

  - **A separate application for rehearing the SONGS settlement** approval decision remains pending with no statutory due dates or a procedural schedule.

  - **Chairman Picker had earlier affirmed the essential prudency** of the SONGS settlement in a formal response to a March 19th letter from California Assembly member Anthony Rendon (Chair of the Utilities and Commerce Committee).

  - **EIX is not a target of the Attorney General's investigation into ex-President Peevey's** conduct. Rather, the company has provided documents as requested and has been treated as a cooperating witness so far.

- **Proposed Decision supports EIX proposal on rate design, fixed charge and rate tiers.** On April 21, two ALJs issues a PD for the company's filing regarding proposed fixed charges and rate tier reform. The PD recommends support for the company's proposed two-tier system (down from the current four) that would reduce the cost shifting that occurs when higher-usage, higher-rate tiers effectively subsidize lower-usage customers on a lower rate tier. As expected, the new rate design would be phased in through 2018 but fixed charges are postponed until 2018 (and would include Time of Use TOU rates as well). As a reminder, EIX had proposed a fixed charge as the best way to ultimately reduce the subsidization of rooftop solar for system costs that happens when rates are charged volumetrically. The company's proposal had started at $5/mo in 2015 (vs. $0.95/mo today), climbing to $7.50/$10 per month by 2016/2017, respectively. As for variable rates, the company negotiated a settlement to see its lowest tiers (1 & 2) increase this year to 14.85c and 19.28c, respectively for the current year following a settlement penned in March.

- **Expect the winner of the Delaney Colorado River Transmission Line** contract under CAISO's competitive solicitation to be announced in August (in-service in 2020). EIX is now a partner with PNW and MidAmerican against four other competitive bidders.

- **Electric vehicle proposal.** EIX's proposal (along with PCG's and SRE's) could be a significant source of ratebase growth. All of the California utilities have asked for expedited approval this year, but only EIX has a small $22M pilot

proposed for 2015/16. If approved, this would be followed by a $333M Phase 2 for an additional 28,500 chargers from 2016-2020. EIX is projecting that this will address about 1/3 of ~$1B market in 2020 for non-single family home charging demand within Southern California Edison territory alone.

- **Tax benefits from bonus depreciation and other effects could continue to add** to earnings in various quarterly reporting periods going forward. For now, the company is reserving against these benefits pending the GRC outcome. With the utility becoming a cash taxpayer in 2H15, we expect the company to take more bonus depreciation in both 2015 and 2016.

- **ERRA deferrals.** With gas prices low, the company is has been overcollecting for energy lately, which enables them to defer amortized recovery of remaining balances of the Energy Resource Recovery Account (ERRA). As of end of May down to $666M from north of $1B last year and the utility has asked regulators to rescind an earlier requested ERRA rate increase.

Why else do we still like shares?

- **ROE extension in place:** We expect a deal later this year or early next to extend its cost of capital construct for another 1-year extension (such a deal was already cut for this year); as a reminder, the ROE is already formulaically linked in the state to shifts in corporate bond rates. The principle question is whether the linkage rate should be adjusted.

- **Cost cut updates?** Following a similar update from PCG, we would expect EIX to provide an updated view of its pro-forma cost structure upon rate case resolution later this year.

- **Management intends to be more aggressive and grow the dividend faster than earnings.** After a meaningful 17.6% dividend increase in December, management plans to continue to grow the dividend in steps and in-line with earnings growth in order to eventually return to the targeted payout ratio of 45%-55% (vs ~31% currently). We project a 16% CAGR through the 3-year period.

Distribution System Upgrade Plans Filed

On July 1, all three publicly owned California utilities filed their Distribution Resource Plans (DRP) as required under AB 327, the law that was passed in Oct 2013 to direct the development of plans for future distribution resource management and integration as well as the redesign of the state's rate tier structure and new net metering policies. The purpose of these plans is to eventually create a system that can easily accommodate the "plug and play" of "distributed energy resources" (DER), such as solar, wind, demand response, energy efficiency, battery storage, electric vehicles, and other behind-the-meter energy supply devices. Rather than the current system designed around central station one-way flow out to customers, the system of the future would be able to manage and optimize two-way flows from a wide variety of distributed generation and efficiency equipment. The plans are required to evaluate locational benefits and costs of DERs, identify new tariffs, contracts, barriers to deployment of new technologies, and determine any additional utility spending necessary to upgrade the grid with the goal of yielding net benefits to ratepayers.

The critical point to emphasize is that these plans form the basis for future capex growth for these companies. While spending levels will still be established through

the GRC process, the DRPs provide the outlines for capex plans to be presented through these respective filings – and add credibility to future year continued ratebase growth for California utilities.

Southern California Electric's (SCE) plan provides a "roadmap" for the evolution of the grid to both integrate DERs as well as support for California's ambitious greenhouse gas (GHG) reduction goals. Capital spending levels for the foreseeable future are still expected to be the same $4.0B-$4.5B per year, with the plan expected to simply fortify and probably extend this level of growth deeper into the 2020s (rather than increase near term annual levels). However, should the state decide to accelerate the program, we believe higher levels of near term capex would likely be required. SCE proposes the creation of a DER memo account to recover spending for grid modernization and demonstration projects from 2015-2017. After that, recovery would be filed within the next expected base rate increase for test year 2018.

EIX capital spending levels for the foreseeable future are still expected to be the same $4.0B-$4.5B per year.

This is unchanged vs. prior guidance and implies a slight slowing the growth rate off recent highs (still ~7%)

Figure 94: Estimated SCE Distribution Resource Plan Capex through 2020

Capital Expenditures	2015-2017	2018-2020
Distribution Automation	$40-70 million	$185-320 million
Substation Automation	$30-60 million	$185-320 million
Communications Systems	$7-15 million	$270-470 million
Technology Platforms and Applications	$130-200 million	$215-375 million
Grid Reinforcement	$140-215 million	$550-1,100 million
Total	$347-560 million	$1,405-2,585 million
Recovery method	Memo account	2018 TY GRC

Source: EIX Company filings

The plan includes three 10-year scenarios with increasing levels of aggressiveness as outlined in the table below. Note the expected declines in load growth as a result of high levels of DER deployment.

Note the expected declines in load growth as a result of high levels of DER deployment.

Figure 95: SCE Amounts of DER Deployment by 2025, 10-year Scenarios

SCE Amounts of DER Deployment by 2025	Current SCE Territory Installed Capacity	Scenario 1 "Normal growth"	Scenario 2 "High Growth"	Scenario 3 "Very High Growth"
Base Load		27,019 MW	27,019 MW	27,019 MW
Solar PV (nameplate AC)	1998 MW	1,636 MW	1,905 MW	4,770 MW
AAEE (annual)	1,122 MW	10,536 GWh	17,031 GWh	17,243 GWh
Demand Response	1,177 MW	1,265 MW	2,087 MW	2,981 MW
CHP (annual)		6,350 GWh	8,576 GWh	13,612 GWh
EV (annual)	57 MW	2,422 GWh	3,395 GWh	3,395 GWh
Storage (D&C)	7 MW	270 MW	270 MW	637 MW
Storage (T)		310 MW	310 MW	731 MW
Expected 10-year SCE load growth rate	1.4%	1.0%	0.9%	0.2%

Source: Southern California Edison Distribution Resource Plan

- SCE proposes public workshops and the following procedural schedule.
  - Responses/Protests due: August 3, 2015
  - Reply to Responses/Protests: August 17, 2015
  - Workshops September – October 2015
  - Opening Briefs: November 13, 2015
  - Reply Briefs due: December 18, 2015
  - Proposed Decision: February 10, 2016
  - Comments on Proposed Decision: March 1, 2016
  - Replies to Comments: March 7, 2016
  - Final Commission Decision: March 2016

Estimates unchanged pending 2Q update

After 1Q, we tweaked down our 2015-2016 estimates a few pennies to account for timing of capex while our 2017-18 estimates remained unchanged.

Figure 96: Summary Mini-Model for EIX, 2014E-2018E

EIX Mini Model	2014	2015	2016	2017	2018
Ratebase (midpoint) - including all adjustments below	22.4	23.4	25.5	27.7	29.1
Ratebase growth		4.2%	9.2%	8.4%	5.3%
% FERC	22.0%	22.7%	22.9%	23.0%	23.5%
CPUC ROE	10.45%	10.45%	10.45%	10.45%	10.45%
FERC ROE buildup					
FERC Base Rate	9.30%	**	9.77%	9.77%	9.77%
CAISO (RTO Participation Adder)	0.50%	**	0.50%	0.50%	0.50%
Avg. Project Incentive Adder	0.65%	**	0.65%	0.65%	0.65%
FERC ROE	10.45%	10.45%	10.92%	10.92%	10.92%
Equity%	48.0%	48.0%	48.0%	48.0%	48.0%
Shares (basic)	326	326	326	326	326
Shares (diluted)	329	329	329	329	329
Ratebase EPS					
Ratebase EPS before adjustments below	3.45	3.59	3.96	4.30	4.53
SONGS shutdown	(0.06)				
Income tax benefit	0.51				
Cost savings	0.74	0.12	0.15	0.15	0.15
Energy efficiency	0.04	0.05	0.03	0.03	0.03
Parent & other	(0.09)	(0.13)	(0.13)	(0.13)	(0.13)
Total EPS (basic)	4.59	3.63	4.01	4.35	4.58
Total EPS (diluted)	4.55	3.60	3.98	4.31	4.54
Previous UBSe	*$ 4.55*	*$ 3.60*	*$ 3.98*	*$ 4.31*	*$ 4.54*
Consensus	*$ -*	*$ 3.60*	*$ 3.90*	*$ 4.20*	*$ 4.46*

Source: UBS Estimates, Company filings, FactSet

Capex is still expected to remain around the historical ~$4B level, supporting a growing dividend as ratebase and cash flow grow over time into the next decade.

Our 2017+ core EPS reflects increased spending for distributed generation and electric vehicle supporting infrastructure. We expect a significant increase in spending opportunities once the coming Distribution Resources Plan is finalized and expanded upon through the ratecase process (see below for details). However, management indicated that post-2017E, annual capex is still expected to remain around the historical ~$4.0B-$4.5B level, supporting a growing dividend as ratebase and cash flow grow over time into the next decade. No secondary equity issuances are contemplated through for the foreseeable future.

Figure 97: SCE Requested Capex and Ratebase, 2014E-2017E (new forecast vs priors)

CAPEX ($M)	Nov-13	Feb-14	Nov-14	Feb-15	Apr-15
2014E	*$ 4.0*	*$ 4.1*	*$ 4.1*		
2015E	*$ 4.2*	*$ 4.5*	*$ 4.2*	*$ 4.1*	$ 4.1
2016E	*$ 4.4*	*$ 4.4*	*$ 4.6*	*$ 4.8*	$ 4.6
2017E	*$ 4.2*	*$ 4.2*	*$ 4.5*	*$ 4.5*	$ 4.4
Ratebase ($M)	**Nov-13**	**Feb-14**	**Nov-14**	**Feb-15**	**Apr-15**
2014E	*$ 22.4*	*$ 22.4*	*$ 22.4*		
2015E	*$ 24.7*	*$ 24.4*	*$ 24.0*	*$ 23.8*	$ 23.6
2016E	*$ 27.1*	*$ 27.0*	*$ 26.7*	*$ 26.2*	$ 26.0
2017E	*$ 29.3*	*$ 29.2*	*$ 29.3*	*$ 29.0*	$ 28.4

Source: Company Filings and UBS Estimates

Valuation: Reduce PT $4 to $66 on lower peer P/E multiple

Our valuation is based on a 2017E average utility P/E with a 1x-turn premium to regulated peers for the California jurisdiction assets and a 1.5x premium for FERC

regulated transmission. We also subtract out our -$0.15 estimate for 2017 cost savings as these will be absorbed back into customer rates in the 2018 GRC. Our base case assumes a SONGS ex-parte penalty of 10% the ORA request of $648M (essentially immaterial). Our low case assumes the full $648M (~$1/sh after tax).

Our premium valuation continues to be supported by several factors: With no requirement for the commission to act upon TURN's request – and having already affirmed the settlement previously, we see little by way of CPUC precedent to see such a move at present. Also, our discussions with various parties indicate broad support for another one year extension for the next Cost of Capital ratecase, with a filing potentially pushed as far out as mid-2017.

Figure 98: EIX Earnings Estimates

Sum of the Parts Analysis - UBSe										
		2017E EPS			**P/E Multiple**				**Value Per Share**	
Base Case Scenario:										
			Low	*Group*	*Discount/ Premium*	Base	High	Low	Base	High
SCE Estimate		$4.46								
CPUC	77.0%	3.43	14.7x	14.7x	1.0x	15.7x	16.7x	$50.46	$53.90	$57.33
FERC	23.0%	1.03	15.7x	16.2x		16.2x	16.7x	16.10	16.61	17.12
Parent Drag		(0.15)	14.7x			15.7x	16.7x	(2.21)	(2.36)	(2.51)
Cost savings clawback in 2018		(0.15)	14.7x			15.7x	16.7x	(2.21)	(2.36)	(2.51)
SONGS penalty contingency ($M)			$ (648)	Probability	10%	$ (65)		(1.18)	(0.12)	-
Implied Valuation		$4.31						$61.00	$66.00	$69.00

Source: Company Filings, FactSet, and UBS Estimates

Empire District Electric (Sell; $21 PT)

We estimate that Empire District Electric will report 2Q15 adjusted EPS of **$0.21**, a penny miss vs street consensus at $0.22; and a decline from $0.26 in 2Q14. One of the main headwinds this quarter was a couple of pennies hit from below average Cooling Degree Days in the west north-central region (albeit this is similar to the weather impact in 2Q14); a penny hit on property taxes etc. arising due to regulatory lag. Based on a $10mn YoY increase in guidance, we also estimate a $0.03 negative impact from D&A; and a $0.01 negative impact from O&M coming from cost inflation and higher maintenance at Riverton.

We expect a penny miss vs consensus

Figure 99: 1Q15 Earnings Walk

EDE 2Q15 Earnings Walk	EPS	Comments
2Q14A Adj. EPS	**$0.26**	
Margin		
Rate Relief	$0.01	*New MO rates ~Aug. and AR rates Sept '14*
Customer Growth	$0.01	*Pretty flattish (<1%); Mercy Hospital online March 2015*
Reversal of Weather	$0.02	*Reversing 2Q14 weather*
Weather in Quarter	($0.02)	*Below average CDDs in West North Central*
Gas Segment & Other	$0.01	*Slight increase*
O&M	($0.01)	*Organic cost inflation & Riverton Maintenance*
Depreciation & Amort.	($0.03)	*Organic cost inflation: $10Mn YoY increase guidance*
Property Taxes & Other	($0.01)	*Regulatory lag*
Interest Expense	($0.01)	*$60Mn issued in December '14; Another $60Mn in '15*
AFUDC	($0.01)	*Spending on Riverton CT (~$175Mn capex but reg. lag)*
Dilution & Other	$0.00	*~Immaterial increase from DRIP*
2Q15E Adj. EPS	**$0.21**	
Consensus	***$0.22***	
2015 Guidance	***$1.30-1.45***	
2015 UBEs	***$1.38***	
2015 Consensus	***$1.38***	

Source: Company Filings, FactSet and UBS Estimates

For additional context, please refer links to relevant recent reports below:

5/11/15 Stuck in a Growth Quagmire
2/10/15 Structurally Lagging?
1/8/15 Staying Small – Downgrade to Sell
11/4/14 Addressing the Growth Conundrum via T&D Spend
8/6/14 Reconciling the Earnings Growth Problem

What's New With Empire District over Q2?:

- **Settlement approved in MO**

The Missouri Public Service Commission approved the settlement in Empire District Electric's pending rate case last week with new rates effective on July 27 (in-line with expectations). However the PSC approval does not include EDE's request to include *all* transmission-related costs associated with its participation in the SPP regional transmission organization market, in the FAC.

The PSC approval does not allow *all* SPP transmission-related costs in the FAC

The transmission recovery in the FAC allowed relates to future changes in transmission expense which mgmt. estimates is only ~34% of SPP transmission expense. The costs that PSC has approved for FAC inclusion are: 1) transmission costs to serve its native load, that is sourced from generation plants not owned by the company ("true purchased power"); and, 2) transmission costs for excess power the company sells to third parties in locations outside of SPP (off-system sales). EDE had proposed to also include costs associated with power that the company produces, sells into the SPP market, and subsequently repurchases for its native load – and this was rejected. As such, we note risk here for the company associated with costs increasing above those reflected in its base rates.

- **On schedule for next rate case filing**

With respect to its next rate case to address recovery of costs associated with the Riverton 12 gas conversion project (from a simple-cycle unit to a combined-cycle unit), mgmt. said they are on track for a filing towards the end of 2015. The project is expected for completion in mid-2016, with costs estimated in the $165-$175mn range. The rate filing should ideally be in advance of completion such that mgmt. can get it included in a true-up and minimize the regulatory lag.

- **Private placement debt financing to settle in August**

The company entered into a bond purchase agreement on June 11 for a private placement of $60Mn of 3.59% First Mortgage Bonds due on 2030. Mgmt. said they expect the financing to settle in August. The company will likely use the proceeds to refinance existing debt and to finance ongoing projects including Riverton. The issuance should help retain the 50%/50% capital structure. As a reminder, EDE issued 4.27% notes in a December $60Mn private placement.

No updates to our EPS Estimates

We present our EPS estimates below which reflect the pending settlement in Missouri; as a reminder management's guidance assumed that the Missouri customer rates matched the filing request. An acceleration of the rate case process could be a positive to FY15 results but management currently expects the timeline to remain intact despite the proposed settlement.

Figure 100: EPS Estimates

EDE EPS Estimates	2014A	2015E	2016E	2017E
UBS Estimates	$1.55	$1.38	$1.47	$1.54
Guidance		*$1.30-1.45*		
Prior *estimates*		$1.38	$1.47	$1.54
Consensus estimates		*$1.38*	*$1.48*	*$1.60*
Implied Earned ROE				
Using Ratebase Math	*8.1%*	*6.7%*	*6.8%*	*7.1%*
Using GAAP Average	*8.8%*	*7.6%*	*7.9%*	*8.1%*
~GAAP Regulatory Lag	1.2%	2.4%	2.1%	1.9%
Approx. Guidance	125-150bp	Over 200bp		<200bp

Source: Company Filings, FactSet and UBS Estimates

A few words on ROE: Continue to expect Rising ROEs beyond '15

The implied ROE from the guidance for 2015 is ~7.4% which is roughly in-line with the average earned ROE from 2009-2013. If management is able to get Riverton 12 conversion completed in mid-2016, in-line with expectations, it can file for a rate case in January to capture the in-service in the true-up period. In this scenario new rates would be unlikely before November, still leaving management with a fair share of regulatory lag. When new rates come in during late 2016 this should position EDE for a healthy 2017 with nearly a full-year of higher revenue and a reduced level of lag.

Valuation: Reduce Price Target $1 to $21; Still Cautious

We use 2017E P/E median for small cap peers, and lower our PT $1 based on this peer multiple revision. We continue to apply a formal five percent discount to peers given the regulatory lag headwinds that diminish near-term earnings growth. The lack of meaningful earnings growth and a challenging regulatory jurisdiction reduces the probability of being a takeout target and contributes to our discounted view.

Figure 101: Updated EDE Valuation

Empire District Electric Valuation: P/E Derived on 2017 EPS					
Downside Case		***Base Case***		***Upside Case***	
Valuation		**Price Target**		**Valuation**	
2017 EPS	$1.54	2017 EPS	$1.54	2017 EPS	$1.54
P/E Multiple	14.2x	P/E Multiple	14.7x	P/E Multiple	15.2x
(Disc)/Prem.	-10%	(Disc)/Prem.	-5%	(Disc)/Prem.	10.0%
Value	**$20.00**	**Value**	**$21.00**	**Value**	**$26.00**

Source: Company Filings, FactSet and UBS Estimates

EDE shares are now trading at a 0.1x discount to the small-cap group median but are in-line with mid-caps we track. Part of the upside thesis for shares revolves around external M&A (SMid Bid) but we see the discount to peer small-caps as appropriate given the unfavorable regulatory environment.

Figure 102: Small-Cap Peer Group

Company	Tkr	UBS Rating	Market Cap ($ mill)	Price 7/11/2015	Dividend Yield	P/E 2013A	P/E 2014E	P/E 2015E	P/E 2016E	P/E 2017E	2016 Rel. P/E
Black Hills Corp	BKH	NR	$2,099	$46.84	3.46%	19.3x	16.2x	16.4x	15.4x	14.8x	0.99x
Cleco Corp	CNL	NR	$3,262	$53.93	2.97%	21.3x	19.7x	22.1x	21.6x	NA	1.39x
El Paso Electric	EE	NR	$1,472	$36.45	3.24%	16.6x	16.1x	18.2x	14.0x	13.6x	0.90x
Idacorp	IDA	NR	$2,924	$58.07	3.24%	16.0x	15.1x	15.6x	15.3x	14.8x	0.98x
The LaClede Group	LG	NR	$2,324	$53.64	3.43%	18.7x	17.6x	16.9x	15.9x	15.6x	1.02x
MGE Energy	MGEE	NR	$1,395	$40.24	2.81%	18.6x	17.3x	17.9x	17.1x	16.4x	1.10x
NorthWestern Corp	NWE	NR	$2,383	$50.66	3.79%	20.6x	18.9x	15.9x	15.0x	14.4x	0.96x
Otter Tail Corp	OTTR	NR	$1,017	$27.13	4.53%	17.6x	15.0x	17.4x	15.5x	14.7x	1.00x
South Jersey Industries	SJI	NR	$1,724	$25.19	3.99%	16.6x	16.1x	15.1x	14.9x	14.0x	0.96x
UIL Holdings	UIL	NR	$2,678	$47.30	3.65%	20.7x	20.9x	19.7x	18.5x	17.3x	1.19x
Unitil Corp	UTL	NR	$471	$33.72	4.15%	21.5x	18.8x	18.0x	17.3x	16.1x	1.11x
Average					**3.57%**	**18.9x**	**17.4x**	**17.5x**	**16.4x**	**15.2x**	**1.1x**
Median					**3.46%**	**18.7x**	**17.3x**	**17.4x**	**15.5x**	**14.8x**	**1.0x**
Empire District - UBS	**EDE**	**Neutral**	**$987**	**$22.63**	**4.60%**	**14.7x**	**14.6x**	**16.4x**	**15.4x**	**14.7x**	**1.0x**

Source: Company Filings, UBS, FactSet

Entergy Corp. (Neutral; $76 PT)

Expect a Miss as the Vortex is Gone.

We look for 2Q to be a modest miss at **$0.96** vs Street at $1.13. The quarter is primarily driven by heawinds from higher O&M at both EWC and the utilities, more outage days, lower hedges (~$3/MWh lower). With management having guided that its advantageous tax rate for FY EPS guidance biased towards the back half of the year, the tax benefits helping the quarter (23% guided vs. 40% last year) may not materialize.

All-in, we see at least ~$0.15 downside vs. Street consensus at present with a bias to the downside.

Seeing sales growth at 2.7% materialize for the year remains of disproportionate importance into 2Q following a weak normalized figure reported with 1Q. Should ETR put up a second consecutive quarter of weaker sales figures, investors may well read this as commentary around it's prospective ability to hit '16 and '17 adjusted sales figures, most recently affirmed at the EEI Conference last November.

Figure 103: ETR – Weaker 2Q YoY

2Q14A	**1.11**
EWC	
VY Going Away (EBITDA Impact)	0.04
NDT Net Expense	(0.02)
Outage Days (30-35 for Pilgrim, and IP3 down 20-days)	(0.08)
O&M - EWC (excl VY impact)	(0.10)
MtM on Hedges for 2Q YoY	(0.09)
Utility	
Weather vs. Normal 1Q15	0.05
Sales (3%+ Growth)	0.09
Rate Actions (~ No Net Rate Increases)	-
O&M, Depreciation, and Interest	(0.14)
Tax Item- Benfits in 2H15	0.11
Net Changes	***(0.15)***
2Q15E	**0.96**
Consensus	***1.13***

Source: Company Filings, Factset, and UBS Estimates

For additional context, please refer links to relevant recent reports below:

2/9/15 EWC Slipping Deeper into the Bayou
10/6/14 Dropping the Danskammer on New York
9/24/14 Lone Star State Continues to Shine
9/10/14 Squaring the Texas Load Growth Enigma
8/27/14 Articulating a Regulated Recovery Strategy
8/4/14 Power Crossroad: Still Not Quite the Time

Major Items of Note

- **Entergy Arkansas – Rate case proceeds, with focus on settlement:** With the new legislation now fully behind the company, the key question now turns to whether it will be successful in achieving a settlement in its pending Arkansas case. This would be necessary by the end of December, prior to going into hearings in the case. We caution that this date could yet slip out in order

to accommodate further time prior to hearings to allow for a settlement. Rates remain targeted for ~March timeframe in 2016.

- **Sales growth figures:** Following close attention to the targets reiterated at EEI last year of 3.25-3.75% CAGR through 2017, as well as 2015 guidance of 2.7% figure, we see investors as closely watching for any slippage in these figures following a weak 1Q (+1.5% only).

- **The further question is do sales matter?** Management appears swift to point out that ratebase growth remains the core of earnings growth; more to the point, much of its anticipated spend is already in place, with less exposure to sales growth variability than would otherwise be suggested. Rather, the question remains should sales growth fail to materialize, can management earn their allowed ROE in 2016, as implied in their long-term guidance. We see this task as further meriting some attention given the timing of the AR rate case (which will provide only a partial year uplift in 2016 under the new construct).

- **What's embedded in guidance? Earning its ROE.** Management has already baked into both its 2016 and 2017 net income guidance ranges the assumption it will earn its authorized ROEs in all jurisdictions in both years (~10% on a weighted authorized basis). *While somewhat aggressive as a baseline assumption, with the AR legislation in place, we see this as entirely achievable. We suspect earning at the upper end of allowed ROEs in Louisiana could yet offset rate lag through the period in Texas.*

- **How is ROE impacted by the AR bill?:** The latest Arkansas legislation would *also* at least require the AR PSC to consider methodologies *other* than just a DCF approach in establishing its authorized rates. Note that the reduced 9.5% ROE in the state is a function of the lower rate environment. The question is whether the commission will continue to push down its authorized level as a result of the lower rate environment today vs. last year when rates were established. Recall the ROE was actually revised slightly upwards from 9.3% initially upon rehearing.

- **Louisiana focus remains on executing the merger:** Amidst recent focus on whether rate treatment is equitable, we see as crucial the successful integration of the Entergy Gulf States and Entergy Louisiana jurisdictions. We see a risk of over-earning at Gulf States if that the company fails in executing this within a timely fashion. Management is in settlement discussions to resolve pending issues, primarily associated with rate design (how to *fairly equalize* the new rates across all customers?).

Another set could open the landscape to allowing utilities to make gas reserve investments with ratebase returns.

- **Texas: Pushing the legislative angle.** While we remain more sanguine on its odds here, the ask is not quite as large either. What is being contemplated in the latest amended version of the proposed bill includes elements largely meant to reduce, albeit not eliminate regulatory lag such as creating a statutory deadline for proceedings. The legislation would primarily allow utilities to set rates effect 45 days after filing, through the full period contemplated by management.

- **All quiet on the Nuclear front?** Don't expect much here, aside for continuing noise around potential development of the CPV Valley CCGT plant adjacent to the Indian Point plant. We emphasize the recent New York capacity auction results were more constructive than we had initially contemplated, particularly for the LHV region. We remain sanguine on the long-term odds of success –

and see a medium-term deal as more likely than anything else affording both NY and the company some amount of visibility for each to engage in planning.

- **Hedges: Lots more?** The question remains how hedged the company is

- **What's the path forward on the Coastal Zone Management license?**

Updating Estimates to Reflect MtM

Our latest updated estimates reflect MtM shifts on the curve for 2016+ onwards. We continue to assume regulated earnings towards the top end of it's regulated net income guidance ranges for both 2016 and 2017, reflecting an ability to largely earn it's ROE across all its jurisdictions.

Figure 104: Latest Entergy EPS Estimates

EPS by Segment	2012A	2013A	2014A	2015E	2016E	2017E	2018E	2019E
Regulated Utility	5.50	4.80	4.64	5.66	5.74	6.07	6.33	6.71
EWC/Nuclear	1.49	1.47	2.19	0.82	0.40	0.15	(0.12)	(0.28)
Other	(0.76)	(0.91)	(1.00)	(1.02)	(1.15)	(1.22)	(1.11)	(1.16)
Consolidiated	6.23	5.36	5.83	5.47	4.98	5.01	5.09	5.27
Previous	6.23	5.36	5.83	5.41	5.10	5.29	5.50	5.69
Guidance Range				5.10-5.90				
EPS CAGR (2013A-2016E)		Guidance	2-4%	UBSe	-2.40%			
EPS CAGR (2013A-2017E)		*Also 2-4% --->*			UBSe	0.64%		
Consensus			*5.83*	*5.42*	*5.26*	*5.50*		
EPS Guidance -Regulated Utility				5.70		5.80-6.10		

Source: Company reports ad UBS estimates

Valuation: Updated Sum of the Parts Approach

We include our latest SOP, reflecting our decrease by $3 to $76 PT. We see merit to seeing a positive re-rating in shares following the successful passage of legislation in AR. We have updated our utility SOP to reflect a breakout utility valuation by jurisdiction. As the company's business profile increasingly shifts towards its regulated proposition, we see a need to shift towards

- We are reflecting a -1.0x P/E multiple to Arkansas, a -1.0x P/E multiple to New Orleans and a -2.0x P/E to Texas given historically lower ROEs and greater risk profiles around earnings outcomes. We remain intrigued to see to what extent recent legislation in AR will enable the company to earn it's authorized ROE through the ongoing rate case.

- In contrast, we are ascribing an inline P/E multiple to both Louisiana utilities (Gulf States and Lousiana) to reflect our more constructive views around their respective Formula Rate Plans (FRPs) at each of these jurisdictions. We are also more constructive on account of contemplated future sales growth, limiting the need for meaningful future rate increases. That said, overall growth remains only inline or below peers.

- We reflect an inline multiple for its Mississippi jurisdiction. We appreciate the segment's evergreen Formula Rate Plan (FRP), however caution against a fuller multiple seeing relatively less growth at the jurisdiction.

Figure 105: Sum of the Parts Analysis - using P/E on Utility and EV/EBITDA on Merchant Generation

All figures in US $ million except per share data	2017E EPS/EBITDA	EV/EBITDA and P/E Multiple						
			P/E Multiple				Equity Value	
	2017 EPS	Low	Prem/Discount	Base	High	Low	Base	High
Regulated Utilities		2017 Peers	15.5x					
System Energy Resources, Inc. (SERI)	0.80	14.5x	0.0x	15.5x	16.5x	11.57	12.37	13.17
Entergy New Orleans	0.20	13.5x	-1.0x	14.5x	15.5x	2.74	2.95	3.15
Entergy Mississippi	0.85	14.5x	0.0x	15.5x	16.5x	12.36	13.21	14.06
Entergy Louisiana	1.72	14.5x	0.0x	15.5x	16.5x	24.96	26.69	28.41
Entergy Gulf States (Louisiana Only)	1.09	14.5x	0.0x	15.5x	16.5x	15.79	16.88	17.97
Entergy Texas	0.59	12.5x	-2.0x	13.5x	14.5x	7.35	7.94	8.53
Entergy Arkansas	0.95	13.5x	-1.0x	14.5x	15.5x	12.86	13.81	14.76
Other	(0.14)	14.5x	0.0x	15.5x	16.5x	(1.97)	(2.10)	(2.24)
Regulated Utility (Consolidated)	6.07					85.67	91.74	97.81
Parent Preferred Income	(0.70)	14.5x	0.0x	15.5x	16.5x	(10.21)	(10.92)	(11.62)
Other Parent Exp (non-Pfd)	(0.13)	14.5x	0.0x	15.5x	16.5x	(1.87)	(2.00)	(2.13)
Utility Value: T&D Segments	5.24	*14.5x*	*14.1x*	*15.1x*	*16.1x*	73.59	78.82	84.06
Total Utility Equity Value per Share						$73.59	$78.82	$84.06
EWC Value is a Proxy for NPV of Hedges /			EV/EBITDA Multiple				Enterprise Value	
Indian Point	2017 Adj. EBITDA	Low	Prem/Discount	Base	High	Low	Base	High
Nuclear and Wholesale Gen	422	3.0x	0.0x	5.0x	7.0x	$1,265	$2,108	$2,952
Hedges	(67)	3.0x	0.0x	5.0x	7.0x	(200)	(333)	(467)
Total / Implied	355	*3.0x*		*5.0x*	*7.0x*	$1,065	$1,775	$2,485
Parent + EWC Debt							(3,041)	
Less: Parent + EWC Cash							152	
FCF through end 2016							394	
Net Debt (Parent+EWC)							(2,494)	
Add/(Subtract): Hedge Value NPV							331	
Subtract: NYPA Value Sharing Payment (expires '14; Paid in '15)							(72)	
Merchant Generation Equity Value/(Drag)						(1,098)	(459)	323
Mn Shares Outstanding (2017E)						180	180	180
Merchant Generation Equity Value per Share						($6.09)	($2.55)	$1.79
Total Equity Value per Share						$67.00	$76.00	$86.00

Source: Company Filings, Factset, and UBS Estimates

Eversource Energy (Neutral; PT $49)

In-line quarter seen with -$0.03 of mild weather. Also need to add back 1x $0.10 charge in 2Q14 for transmission ROE reduction.

For 2Q15 we expect an in-line report at **$0.54** vs consensus $0.55. Weather was mildly warm in April and May, reducing gas heating load but boosting electric A/C load in May. June was mildly cool, depressing electric load. O&M for 2Q15 was lower than last year by a couple of pennies as crews got back to maintenance after heavy winter snow that pushed off some work in 1Q. Overall, still expect -2% decline in O&M costs this year in total. The $130M CL&P rate increase in Dec is offset by $50M applied to storm balance amortization, leaving an $80M effective annualized impact, or +$0.04 for the quarter. Transmission ratebase growth of $400M at an overall average ROE of 11.5% helps a couple of cents, although this is offset by a couple of cents of drag from a lower ROE this year (11.5% vs 12.5% previously). Distribution system growth helps another penny. These are offset by -$0.05 of interest, D&A, and property taxes. CL&P received a favourable order on its Accumulated Deferred Income Tax (ADIT) balance and will begin booking $18M in annual revenues that had been reserved (~$0.03 annualized EPS going forward, with a 1x catchup for 1Q also booked in 2Q).

Figure 106: ES 2Q15E vs 2Q14A Walk

2Q15 YoY EPS Waterfall		
	$0.42	**2Q14**
	(0.03)	Mild April and June. Gas utilities are not decoupled.
	0.01	CL&P decoupling in 2015 (12/1/14) vs no decoupling in 2014
		WMECO has elec decoupling and CL&P gets 2/3 of revenues through fixed charges,
		although CL&P got full elec decoupling on Dec 1. NSTAR elec and PSNH are more
		affected by weather, but less so in 4Q.
20	0.04	CL&P rate decision $130M annualized increase minus $50 to amortize storm balance
	0.01	Gas sales growth 2%, or 10k-11k cust (sales up 3%-4% weax adj)
	0.02	O&M - Heavy snow this winter. In 1Q15, some capital projects were put on hold for the snow,
		so had higher O&M expense in 1Q instead. Expect lower O&M in 2Q. Still expect -2% O&M for the year.
6	0.02	Transmission ratebase growth YoY ~$400M @ 11.5% ROE
	0.10	Absence of -0.10 charge for transmission ROE in 2Q14
(6)	(0.02)	Transmission drag from booking at lower ROE on $4.5B ratebase. 11.5% vs 12.5%
4	0.01	Distribution growth at NU (0.0%-0.5%) - decoupling at CL&P and WMECO (about half the customers)
(7)	(0.02)	Interest - issued $450M debt at parent in Jan at 2.5%
(4)	(0.01)	Depreciation YoY (only 2/3 non-tracked distribution)
(6)	(0.02)	Property & Other Taxes (only 2/3 non-tracked distribution)
	0.02	ADIT earnings after CL&P decision
	-	Parent expense
	-	Inc tax rates
	$0.54	**2Q15**
	0.55	*Street consensus EPS*
	2.75-2.90	2015 Guidance
	2.80	UBSe 2015
	2.85	Consensus 2015

Source: UBS Estimates, Company Filings

On transmission ROEs, ES reinstated its reserve for lower FERC ROEs in 1Q15, with FERC leaning toward applying a transmission ROE cap for New England on a project-by-project basis rather than a whole-portfolio basis. This has the effect of reducing the ROEs to 11.74% for earlier projects in ES's portfolio that had been earning from 12.64%-13.10% (about half the Transmission ratebase – for example, NEEWS and Southwest CT lines built from 2005-2008). As a result, the overall average ROE of the entire portfolio declines from ~12.5% to ~11.5% and forward earnings are impacted by -$0.02 year over year on a quarterly basis throughout 2015.

For more detail on these issues, please see our other recent reports:

5/1/15 Waiting to Commit
4/21 It's Time to Wait and See (Downgrade to Neutral)
4/18 Polar Without the Vortex (1Q15 Earnings Preview) – Page 134
3/12 Scrubbing the Whole Fleet
2/19 Sourcing Solutions for New England
12/17 Brimming With Confidence
12/2 Earning the Allowed: Draft Decision for CL&P
11/17 Rethinking Renewables in the Northeast (Includes Call Transcript)
11/14 Measuring up the Good, the Bad, the Ugly at the EEI Circus
11/10 Minding the Northeast Infrastructure Gap

What's new with Eversource?

- **The company continues to project 6-8% EPS growth rate through 2018**, but this is dependent on both the success of the Access Northeast gas pipeline project as well as the Northern Pass Transmission (NPT) project. While this represents a diversification of large project risk vs the sole reliance on NPT previously, we see at least 30% credit for the pipeline as necessary (and 100% of NPT) to achieve the low-end 6% growth rate. Importantly, ES has been conservative in projecting its possible long-range investment pipeline, with another $1B of potential as-yet undefined transmission opportunities to connect renewable power from Southern New England, New York, and Vermont.

- **The US Dept of Energy is expected to release** a draft Environmental Impact Statement (EIS) for the proposed Northern Pass transmission project sometime in July after more than 6 months of delays. The extra time has been needed to evaluate mostly small modifications of the proposed route as requested by various localities and intervenors. No settlement of any issues regarding NPT is possible until the EIS is out. With a late July draft EIS, the company could file the NH Siting Evaluation Committee by the end of September for a decision by November 2016; then construction and substantial completion by late-2018 followed by testing and entry into full commercial operation in 1H19 (testing must wait until April to avoid the high-load Dec-March timeframe).

Nearly a year and a half delay from the original early-2018 in-service projection.

- **Separately, the New England States Committee on Electricity (NESCOE) has been focussed on establishing legal authority in each state for EDCs to contract for gas pipeline capacity on behalf of electric customers.** We no longer expect a separate RFP for such capacity to be issued directly from the Committee. In the absence of enabling legislation in Massachusetts (which was defeated last year). Projects such as Access Northeast and Northeast Energy Direct are intended to bypass the previously troubled NESCOE RFP process by relying on state authority through distribution rates rather than federal authority through transmission rates.

- **Governor Baker in MA introduced a new renewables bill on July 9.** The bill seeks to procure 18.9 TWhs annually through clean energy resources <u>and associated transmission</u> via long-term contracts from 15-25 years. More specifically, the bill is intended to ensure that approximately

1,200 MWs of hydroelectric power is delivered to Massachusetts in order to meet a 20% greenhouse gas (GhG) reduction target by 2020 as required under the Global Warming Solutions Act (GWSA).

- **On June 25, NESCOE issued a finalized RFP** for the Southern New England states (CT, RI, MA) for 5.1 TWhs of clean energy and renewables, which is 2.75 TWhs higher than the Feb draft version. The upsizing is the result of new CT legislation this year. Once approved by state regulators in MA and RI (no approvals needed in CT), we expect contracts to be announced later this year. With the Northern Pass Transmission Project (NPT) likely to face tough competition for capacity revenues in the New England, the line is more heavily dependent on state renewables mandates through these RFPs and new legislation in MA.

- **Opportunities for further 'Northern' transmission too --** With a full RFP to procurement incremental renewables due out from MA. RI ,and CT by late in 2Q ES appears poised to capture incremental development opportunities by late in the year once final arrangements are signed. The contracts that would be contemplated would include recovery of corresponding transmission to interconnect these renewables.

- Aside just ES' well publicized discussion on the Northern Pass project through NH, we flag **other competing projects** include efforts by Emera-National Grid, Anbaric, and Blackstone as all contributing to a wider concern of new Supply. Recent conversations with Quebecois officials suggest a clear desire to continue to **pursue transmission investments further to the north** to support the mining industry and general economic growth.

- **ES recently filed a slightly smaller 1,090-MW alternative to the 1,200-MW NPT into the ISO-NE interconnection queue.** The filing is not the preferred option but a possible alternative being addressed in the DoE's draft EIS with more undergrounding and different technologies. The reason for the lower capacity is to ensure that it takes a spot toward the front of the queue, providing a viable plan B.

- **FERC continues to consider two remaining transmission ROE complaints** for the periods 1/1/13-3/31/14 and 8/1/14-9/30/15, which have been combined into a single proceeding. Hearings just ended in early July and while there is no deadline or estimated timeframe for a decision on the complaints, an initial decision from the ALJ is due by the end of 2015. We expect a final order in 2H16.

- **In New Hampshire, legislation to implement the PSNH fleet divestiture settlement passed the Senate and House and awaits the Governor's signature (she is supportive).** The legislation is needed specifically to implement securitization of stranded costs as subsidized operations end and customers get their power from market. ES filed a full application for formal approval of the sale in June followed by hearings and approval later this year (and an auction process in 2016).

- **CL&P received a positive decision in July on eligibility in ratebase for certain accumulated deferred income taxes (ADIT) from the CL&P rate decision in December.** The company is booking a reserve for $18M of annual revenues and so a favorable decision could result in as

much an effective rate increase retroactive to Dec 1, 2014. This is worth about +$0.03 per year in incremental EPS. Will see a positive catchup in 2Q for unbooked revenues from 1Q.

- **Yankee Gas rate settlement** in Connecticut was approved in late April, to include a 1-year rate freeze and earnings sharing above a 9.5% ROE. The next 4-year review of Yankee Gas rates isn't required until 2019.

- **ES expects to file in NH for siting approval in 3Q** for their portion of the proposed AC Transmission project (in partnership with National Grid). Public hearings are still underway in NH Recall that the ISO New England Planning Advisory Committee posted its recommendation for the Greater Boston Solutions Study on Feb 12, advising the selection of Eversource and NGG's joint proposal.

- **ES began filing siting applications in March** for $350M of greater Hartford transmission reliability projects. The first of two projects was approved in mid-April, with work to begin this summer.

- **Access Northeast pipeline dependent on state regulatory approvals.** Later this year, the Electric Distribution Companies (T&D utilities) who sign on (including ES and NGG's utilities) will take their firm commitments for deliveries off Access Northeast for state regulatory approval. This is likely to include MA, CT, NH, and RI for all of ES' and National Grid's utilities in the US. Notably, this will not be subject to FERC approval – and will strictly be a state-driven process. CT passed legislation this year to authorize electric utilities to purchase pipeline capacity on behalf of electric customers, joining RI and Maine. New Hampshire is studying the issue and Vermont is not expected to participate. Massachusetts legal authority is a bit more unclear and the Department of Public Utilities (DPU) has opened Docket #15-37 to explore the issue with an eye toward granting authority later this summer/fall, likely under existing statutes.

Notably, this will not be subject to FERC approval – and will strictly be a state-driven process.

- **Access Northeast open season closes May 1.** Precedent agreements are being worked on now and expected later this year with state regulatory filings by the end of the year as well. State regulatory approvals will be needed by 4Q15 to begin construction in time to be in-service for the winter of 2018/19. A FERC prefiling is expected later this year followed by the full filing in mid-2016 after the states have formally approved the EDC and LDC capacity contracts.

- **Opportunities in Maine**. Although nothing has yet been announced, both Access Northeast and Kinder Morgan's proposed Northeast Energy Direct pipeline may compete in Maine's RFP for new gas transportation capacity.

- **NSTAR Gas had hearings in June for its ratecase**, the first one filed in more than 20 years. Briefings in August followed by a decision in Oct/Nov with a rate increase effective Jan 1.

- NSTAR Gas also filed in October a joint plan with other Mass LDCs for a **25-year cast-iron and bare steel pipe replacement plan** with recovery through capital trackers. The filing actually includes two capital trackers: one to replace existing pipes (in process for some work to begin in late 2015) and another for installation of new pipe (not filed yet – expect to file in 3Q). While 2015 spending was approved, we don't expect any material work to begin until 2016 (no recovery in 2015 anyway because of the rate freeze). Going forward, the request will happen each winter in time for the approval before the Spring-Fall construction season.

- **Both CL&P's, WMECO's, and NSTAR Electric's next ratecase filings** are not expected until 2017.

- The pace of **oil-to-natural gas home conversions continues unabated** despite the lower price of oil in recent months. While actual conversion calls have in fact declined somewhat, this has been more than offset by increased economic activity and homebuilding with new gas system installs.

- The ratemaking methodology for the planned $200M upgrade of the 3 bcf Hopkinton **LNG facility has been approved** in Mass. The company is still planning the construction schedule and project implementation.

Projects such as Access Northeast and Kinder Morgan's Northeast Direct are intended to bypass the troubled NESCOE process by relying on state authority through distribution rates rather than federal authority through transmission rates.

MA Proposes Law for more Hydropower and Transmission

As anticipated, on July 9, Massachusetts governor Charlie Baker introduced legislation to require Mass electric utilities to procure a combined annual total of 18.9 TWhs of electricity from clean energy resources and associated transmission via long-term contracts from 15-25 years. More specifically, the bill is intended to ensure that approximately 1,200 MWs of hydroelectric power is delivered to Massachusetts in order to meet a 20% greenhouse gas (GhG) reduction target by 2020 as required under the Global Warming Solutions Act (GWSA). Under the state's 2010 plan, approximately 5.3% of the targeted 25% reduction is expected to be sourced from large-scale firm hydroelectric power.

The new MA bill is intended to ensure that approximately 1,200 MWs of hydroelectric power is delivered to Massachusetts.

Positive for ES' NPT project.

Furthermore, section (d) of the proposed legislation specifically allows separate unbundled transmission proposals that connect "with regions or areas where clean energy generation resources may be available" (i.e., large scale hydro): "Such transmission proposals may provide for procurement separate from the power purchase agreement for the clean energy generation resources or may bundle the transmission into the power purchase agreement." As discussed in more detail below, this law appears tailored to ensure more transmission from Canada is built and if passed would be a significant positive datapoint for ES' proposed Northern Pass Transmission line (NPT).

Upsized NESCOE RFP also solicits clean energy under existing laws

The NESCOE RFP was upsized to comply with the new law in CT which specifically calls for "verifiable large-scale hydropower…and any associated transmission".

On June 25 and 26, the long-awaited clean energy Request for Proposals (RFP) from the New England States Committee on Electricity (NESCOE) was released and submitted for approvals in both Massachusetts and Rhode Island. Connecticut statutes do not require approval for the electric utilities to solicit under the RFP. Notably, the finalized version of the RFP doubles the size of the February draft version with an additional 2.75 TWhs in CT authorized under recently passed Public Act 15-107. This is in addition to another proposed 1.5 TWhs in CT authorized under a 2013 statute and 0.8 TWhs in MA. Importantly, the new law in CT specifically calls for "verifiable large-scale hydropower…and any associated transmission". Note that both the draft and final versions do not specify quantities for RI because statutes there do not cap the procurement. Contract terms for proposals are 20 years for CT (15-20 years for hydropower), 10-20 years for MA, and not specified in RI.

NPT looking better with these state renewable requirements firming up

As noted below, while ES does enjoy an existing contract with HQ for the full offtake of its proposed Northern Pass Transmission (NPT) project, the possibility of not clearing the New England capacity auction places additional reliance on the NESCOE RFP in MA, CT, and RI for 5.1 TWhs of renewable energy this summer (~4.25 TWh in CT, 800 GWh in MA, and a TBD quantity in RI). In NPT's favor is the Massachusetts Global Warming Solutions Act, which would appear to exempt payments for HQ's hydroelectric energy from existing renewable budget caps. The Baker-proposed bill in MA for an additional 18.9 TWhs of clean energy (with emphasis on large scale hydro and associated transmission) is also a positive factor, although there have been concerns this year over the ability to pass anything through committee given an ongoing procedural battle currently happening in the legislature (gridlock). While this bill has the new Governor's support, we remain somewhat cautious given a similar bill's failed efforts in the last session. It would appear that for now, CT remains the primary driver of procurement for large-scale hydro as a 'backstop' procurement for insufficient quantities.

We continue to flag **other competing projects** including efforts by Emera-National Grid, Anbaric, and Blackstone/TDI. Our recent discussion with Emera suggested strong interest in the New England clean energy RFP process. They have specifically cited alternative transmission possibilities, including an offshore underwater "Maine Option", a "Northeast Energy Link" through Maine and New Hampshire, and another offshore underwater "Atlantic Canada" option between Boston and Nova Scotia/New Brunswick.

Clearing New England capacity revenues looks tougher

Following our discussion with ISO NE CEO Gordon van Welie in May, our latest understanding of the New England Forward Capacity Market (FCM) rules suggests that the 'whole' cost of ES' Northern Pass transmission project (NPT) will be included in its bid and that the project will not clear the capacity market. Moreover, the project may not be eligible for the renewable exemption available to in-region renewables. The whole cost appears to include the cost of the US transmission (NPT) as well as the cost of corresponding transmission upgrades in Canada plus the cost of incremental hydro capacity from sponsor Hydro-Quebec (HQ) being delivered (likely in the 2020/21 timeframe). As such, we suspect the

economics are firmly 'out of the band' even when including energy and renewable energy compensation 'at market' prices today. The situation bears some similarity to the recent buyer-side mitigation of both TDI's Champlain Hudson Power Express and the Hudson Transmission Project in NYISO. Without capacity revenues, uncleared projects (like NPT) will face further pressure to derive their economics from the energy market (the diff between power in Quebec vs. New England) as well as from above-market payments for renewable energy contributions (we assume HQ would still be interested in the project). This should assuage wider concerns over structural downside for future New England capacity pricing from transmission. We estimate 1GW+ of new line would crush prices down by as much ~$5/kw-mo (prior to offsetting capacity& other transmission imports coming out of the market). The subject of mitigation has proven exceptionally thorny in NY in recent months with the TDI project in NY ultimately convincing regulators that the project should not be mitigated (and seemingly allowed to clear in the auction in sharp contrast to our latest understanding of the rules in New England).

ES 6%-8% growth rate looks intact

Gaining Confidence in Access Northeast

Completion of either this project and/or the Northern Pass Transmission (NPT) project would allow ES to achieve its stated 6%-8% EPS growth goal through 2018.

We are gaining confidence in the ability of ES, alongside NGG, and SE to successfully build and contract their proposed Access Northeast natural gas pipeline. Completion of either this project and/or the Northern Pass Transmission (NPT) project would allow ES to achieve its stated 6%-8% EPS growth goal through 2018. Our estimates continue to reflect AFUDC earnings booked during the construction period (with a 30% chance of success). The Mass. Dept of Public Utilities (DPU) opened a docket this summer (DPU 15-37) to consider the best way under existing law to approve state electric distribution companies charging customers for capacity on gas pipelines, with the intention of allocating these resources out to independent power generators. This is likely to occur through a third-party manager, analogous to the way an ISO allocates transmission capacity. State regulatory approval is critical to building the two major pipes being considered, Access Northeast and Kinder Morgan's Northeast Energy Direct. We are also watching the docket to see if regulators will require competitive bidding between them as well; we suspect multiple solutions will be necessary to address the litany of challenges. Bottom line, we see the ES outlook as pushing multiple avenues to ensure continued EPS growth despite challenges on the Northern Pass line. We also see the gas pipeline proposal as encountering substantially less pushback, with parties across the sector seeing gas pipes as easing wider concerns around credibility of restructuring in markets following consecutive years of rising prices in the region (that said, the litigation road to execution could prove protracted).

HQ remains enthusiastic; NPT's most critical challenge is NH

ES continues to emphasize that they sense no lack of enthusiasm for the Northern Pass Transmission project (NPT) from its sponsor, HQ, which would like access to relatively high-priced northeast US markets. We believe that the risks and economics of capacity pricing and renewable/clean energy credits are well-known qualitative factors (as discussed below), leaving siting approvals in NH as the primary risk for the project. Governor Hassan's office was quoted in the press recently saying that she "remains opposed to the Northern Pass project as currently proposed and has repeatedly said that she believes that the project must fully investigate burying more sections of the lines." This appears to leave room for

compromise and ES intends to negotiate the project to a successful conclusion after FERC's draft environmental impact statement is released in June/July. As currently proposed, the $1.4B line would utilize 179 miles of existing and new rights-of-way and 7.5 miles of undergrounding. In our opinion, the gating issue for NPT is the cost of additional undergrounding rather than capacity and renewable credit-- although these would be 'nice to haves' in favouring the economics work over competing alternatives.

But what's the timeline for NPT and Access Northeast?

Based on Local Gas Distribution Company (LDC) demand alone, we tend to have greater conviction in the gas pipeline projects vs NPT, although we suspect the timeline to implement either project will stretch into 2016. Given that the MA regulatory docket on gas pipeline procurement authority is generic in nature, resolution is likely to take some time prior to turning into a more formal process on project selection. In the case of NPT, we see the again-delayed EIS approval as delaying the real debate in NH around the siting process into 2016 as well. NH approvals for NPT remain the real hurdle – and negotiating opportunity - for a deal.

Maintain estimates and reduce PT $4 to $49 on lower peer P/E multiple

We include AFUDC during construction in 2019 for ES's 40% ownership of the Access Northeast project (still at a 30% probability). Our PT is reduced $4 to $49 on a lower peer P/E multiple as we continue to value the project by discounting 2019E earnings (at 30% probability) to 2017 and applying a 1.5x premium to the average 2017E utility P/E multiple.

Figure 107: Estimated ES Uplift from Gas Pipe Investment ($ Mn except EPS)

Estimates ES Uplift from Gas Pipe Investment ($M except EPS)		
$M for Aggregate Project		3,000
ES Portion		1,200
Project Equity		50%
Targeted equity return (UBSe)		13%
Net Income Opportunity for ES Project Share	$	78
Parent debt (funding equity contribution)	$	1,200
Assumed cost of Debt		4%
Holdco Interest Expense	$	48
Inc Tax Rate		35%
Net Income Opportunity for ES (net of Parent Int Exp	$	47
Shares O/S		318
EPS Opportunity	$	0.15
2019E EPS	$	3.58
% Potential Uplift to LT (2019E) EPS		4.1%

Source: Company Filings and UBS estimates

Figure 108: ES Estimates vs Consensus, 2013A-2019E

Annual EPS	2013A	2014A	2015E	2016E	2017E	2018E	2019E
Transmission	$0.59	$0.64	$0.68	$0.71	$0.73	$0.74	$0.76
Distribution, Generation	0.83	0.81	0.97	1.00	0.98	1.02	1.05
Yankee	0.13	0.15	0.14	0.15	0.17	0.18	0.19
Northern Pass	0.00	0.01	0.01	0.04	0.16	0.22	0.26
Access Northeast @ 30% probability	0.00	0.00	0.00	0.01	0.02	0.04	0.06
NSTAR, Corp & Other	0.97	1.14	1.00	1.06	1.13	1.21	1.26
UBSe	**$2.53**	**$2.75**	**$2.80**	**$2.98**	**$3.19**	**$3.40**	**$3.58**
CL&P Dist ROE	*7.9%*	*8.6%*	*9.3%*	*9.3%*	*9.4%*	*9.4%*	*9.4%*
PSNH Dist ROE	*9.2%*	*9.3%*	*9.7%*	*9.7%*	*9.8%*	*9.2%*	*9.7%*
Prior	*$2.53*	*$2.75*	*$2.80*	*$2.98*	*$3.19*	*$3.40*	
	$0.00		*$2.85*	*$3.04*	*$3.22*	*$3.42*	
Guidance			**$2.75-$2.90**				
6%-8% EPS growth from 2014 $2.65 to 2018					**UBSe 2014-19 CAGR**	**6.2%**	

Annual EPS, by subsidiary	2013A	2014A	2015E	2016E	2017E	2018E	2019E
CL&P	$ 0.88	$ 0.91	$ 1.03	$ 1.06	$ 1.08	$ 1.12	$ 1.17
PSNH	0.35	0.36	0.39	0.41	0.37	0.37	0.38
WMECO	0.19	0.18	0.23	0.25	0.26	0.27	0.27
Yankee	0.13	0.15	0.14	0.15	0.17	0.18	0.19
NSTAR Elec	0.85	0.95	0.93	0.95	0.94	0.96	0.96
NSTAR Gas	0.07	0.08	0.08	0.11	0.12	0.13	0.14
Corp & Other (includes NPT)	0.01	(0.01)	(0.00)	0.06	0.26	0.38	0.48
Total	$ 2.49	$ 2.62	$ 2.80	$ 2.98	$ 3.19	$ 3.40	$ 3.58
Consensus			***$ 2.85***	***$ 3.04***	***$ 3.22***	***$ 3.42***	

Source: Company Filings, UBS Estimates, FactSet; 2014 and 2013 represent GAAP.

How is our valuation derived?

Our Eversource valuation is based on a utilities sum-of-the-parts analysis, with these two projects valued by discounting their earnings in 2019E to the valuation year and applying the average peer 2017E P/E (with a 1.5x premium for transmission and a 1.0x premium for gas transportation). We attribute ~$4/sh to the Northern Pass project and believe investors could more fully ascribe this in their valuations in 2016-2017 as key project hurdles are achieved. We give a 30% probability weighting to the proposed Access Northeast Pipeline partnership with Spectra and National Grid, worth ~$1/sh in our valuation. We continue to apply the peer multiple to the regulated electric/gas businesses as well as 1x and 1.5x premiums to Yankee Gas and ES Transmission, respectively.

Figure 109: ES Sum of the Parts Valuation on 2017E P/E – Reduce PT $4 to $49 on lower peer P/E multiple

			Low Case		Base Case			High Case	
Sum of the Parts 2017E	**Valuation**		**Valuation**	**($s MM)**	**Valuation**		**($s MM)**	**Valuation**	**($s MM)**
Business Segment	**Metric**	**2017E**	**Multiple**	**Value**	**Multiple**		**Value**	**Multiple**	**Value**
Regulated Business					**Peer Multiple**		**14.7x**		
					Premium				
NU Franchised Electric (CT, NH, MA)	P/E	$0.98	13.7x	$4,282	0.0x	14.7x	$4,594	15.7x	$4,907
NU Transmission	P/E	$0.73	14.2x	$3,298	1.5x	16.2x	$3,762	17.2x	$3,995
NU Yankee Gas	P/E	$0.17	14.7x	$783	1.0x	15.7x	$836	16.7x	$889
NSTAR (MA)	P/E	$1.06	14.2x	$4,770	0.5x	15.2x	$5,106	16.2x	$5,441
Northern Pass 2019 EPS, Discounted 2-Yr	P/E	$0.23	15.2x		1.5x	16.2x	$1,160	17.2x	$1,231
Access Northeast Pipeline 2019 EPS, Discounted 2-Yr	P/E, 30% Prob	$0.06	14.7x		30%	15.7x	$275	16.7x	$292
NU Equity Value				$13,132			$15,733		$16,756
Fully Diluted Outstanding Shares (2017E)				318			318		318
NU Equity Value per Share				**$41.00**			**$49.00**		**$53.00**

Source: Company Filings, UBS Estimates, FactSet

Exelon Corp. (Neutral; $33)

Will the POM deal close in time for the earnings call? Timing could be tight, thereby impacting how much mgmt will disclose about updated synergies, balance sheet latitude, etc.

We forecast EXC reporting adjusted 2Q15 EPS of **$0.53**, in-line with Consensus and up slightly YoY. The theme from 1Q15 continues with the utilities improving from recent rate increases at BGE and ComEd. PECO was +$0.06 in 1Q15 due to the absence of storm costs (+$0.05) and we forecast a flat 2Q YoY for the subsidiary on a more normal basis. The utility growth is mostly offset by ExGen Of note in 2Q is that there is no longer a full quarter of nuclear waste fee elimination benefits and 2Q14 had an extended outage at Salem but those two factors should largely net-out.

Quarter at high-end of guidance and in-line with Consensus. If ExGen declines less than expected we see a path to EXC reporting at the top of the range.

Figure 110: EXC 2Q15 Earnings Walk

EPS	Exelon Earnings Walk
$0.51	**2Q14A EPS**
0.03	**Baltimore Gas and Electric (BGE)**
0.01	Revenues: Rate Increase ($60 Mn December 2014)
(0.00)	O&M, D&A, and Other: Benefits from '14 comp
0.02	Reversal of Bad Debt Expense
0.00	**PECO Energy (PECO)**
0.00	Revenues: Limited Load Growth
0.00	O&M, D&A, and Other: Benefits from '14 comp
0.01	**Commonwealth Edison (ComEd)**
0.03	Revenues: Rate Increase ($233Mn January 2015)
(0.01)	30-year Treasury Trend: 25bp = $0.01/sh
(0.01)	O&M, D&A, and Other: Benefits from '14 comp
(0.03)	**Exelon Generation (ExGen)**
(0.02)	Asset Divestitures: Keystone, Conemaugh, Fore River, etc.
0.00	Asset Acquisitions: Integrys and Proliance Retail Acquisitions
0.01	Refueling Outages - Extended Salem Outage
(0.01)	Energy Margin: Slight Decline
0.01	Capacity: Increase in Avg Price to $144/MW-Day from $135/MWD
0.01	Nuclear Fuel (Amortization offset by disposal fee reduction)
0.01	Benefits at ExGen from serving retail load
(0.00)	D&A and Other
(0.03)	O&M Inflation, D&A, Pension and OPEB, non-power
(0.01)	Interest, Taxes, & Other
$0.53	**1Q15E EPS**
$0.53	***Consensus***
$0.45-$0.55	***1Q15 Guidance***
$2.25-$2.55	***2015 Guidance***
$2.43	***2015E UBS***
$2.45	***2015 Consensus***

Source: Company Filings, FactSet, and UBS Estimates

For additional context, please refer links to relevant recent reports below:

5/5/15 Decisions Looming on the Horizon
4/29/15 Executing Smoothly
2/20/15 Gimme a Number for Ginna
2/17/15 Saving the Nukes? Gimme Ginna.
1/8/15 Spinning The Wheel of Fortune in Illinois

What's new with EXC?

- **EXC accepting Maryland conditions paved the path to approval:** The Maryland PSC ruled on Friday 4/15 to conditionally approve Exelon's acquisition of PEPCO Holdings in a narrow 3-2 vote; however, the PSC imposed 46 conditions on the deal. After reviewing the conditions EXC and POM accepted the requirements of the PSC. Out of the nearly fifty conditions we see a few as key. The largest impact is the creation of a $128Mn Customer Fund (up from $94Mn settlement) with $100 customer bill credits (consistent with the CEG-EXC deal), collectively worth $66Mn (up from $37Mn settlement). Additionally EXC/POM can have no involuntary merger related net workforce reductions for two-years in the state and has to dedicate $4Mn to employee development. Other conditions are focused on reducing negative implications of Exelon's unregulated merchant operations and include additional PJM oversight (must remain in PJM through 2025 and DR bids subject to IMM review) and ring-fencing. Exelon/PEPCO must also contribute towards the development of 15MW of solar. **Please click here for the full Commission Order.**

With Maryland the most challenging jurisdiction in our view, we now see a clear path to approval.

As a reminder, the NJ BPU approved the merger with the condition that its customers receive at least equal treatment from the other approvals, thus amplifying the concessions.

- **Legal complaints unlikely to derail deal at this stage:** While legal challenges have been lodged (and could continue given the case to date) the important factor is that no one has requested a stay in the case. This means that Exelon can close the deal as soon as it receives the last remaining regulatory approval (Washington DC). **Although there is no statutory deadline, historically DC issues a ruling within ~90 days of closing the record which would imply a late-July decision**. As with other recent deals, management expects to be able to close the deal within days of receiving the final approval. Exelon is currently scheduled to report earnings on July 29th so the timing could be tight for material new disclosures about Exelon-post POM but we would expect them to but forthcoming soon after the deal closes.

Despite legal complaints against the proposed merger, EXC can still close the deal shortly after a Washington DC approval.

- **What are the key questions left?:** Depending on the timing of Washington DC approval Exelon may not be in a position to answer these questions yet but we see them as at the top of investors' minds.
  - **Synergies:** Following the prolonged multi-state regulatory approval challenge, how much of the synergy guidance is still intact? We do not anticipate a material reduction but there could be some erosion around the edges.
  - **Earned ROE:** EXC has been successful improving the financial and operating profile of its acquired utilities and we look for details on the game plan to do the same with perennial underperformer POM. At EEI management highlighted that opportunity for ROE improvement at POM as none of the utilities earned their ROEs in either 2012 or 2013. The most room for improvement exists with Atlantic City Electric (ACE) which posted a sub-5% ROE in 2013 and 1.5% the previous year. Aside from just a plan to improve the earnings trajectory, equally important will be the timing over which the improvement is contemplated, particularly given constraints place during the merger approval.

Exelon has improved the earnings trajectories before and we look for concrete details on how it plans to do it again with POM.

- **Corporate balance sheet capacity:** Lastly, the POM deal lowers the risk profile in the eyes of the credit rating agencies which presents the opportunity for incremental debt. We see mgmt. as biased to use its leverage at the parent towards more regulated or contracted deals, opting to use to incremental leverage for future merchant transactions at its ExGen segment (in lieu of parent), although it remains committed to IG ratings at both HoldCo and ExGen. Further details on what the pro-forma balance sheet and cash flows would look like are available in our earlier note, **'Digging Into the Upside Levers'**.

- **Pulling a 'Michael Jordan' on nuclear retirements:** We anticipate an update from Exelon for its Illinois nuclear plants this fall following the PJM auctions and in the midst of the Illinois legislative veto session (October/November typically). A key nuance for Quad Cities is that Exelon can technically decide to retire the plant in September and effectively un-retire the plant within a ~two month subsequent period based upon the outcome of the legislation. The timeframe for a decision on Clinton is ~December and as with Quad Cities is dictated by the need to order a new nuclear core; EXC noted that at a certain point delaying the ordering of the nuclear fuel can become cost prohibitive.

Could be a scenario where EXC retires a nuclear plant only to un-retire it if beneficial legislation is passed in Illinois.

- **PSC to act on Ginna rate collection:** Iberdrola's Rochester Gas & Electric (RG&E) filed with the NY PSC for a temporary rate surcharge effective August 1st for the proposed Reliability Support Services Agreement (RSSA) for Exelon's Ginna nuclear plant to mitigate the rate impact. Although FERC previously partially approved the RSSA effective April 1st, the agreement still requires local approval. From April 1st through July 1st RG&E estimates the deferred collection at $25Mn Additional details on Ginna are available in our previous note **'Gimme Ginna'**

- **Taking a Texas step forward:** Exelon began construction on its 1GW Colorado Bend CCGT on July 8th with construction expected to commence at the other 1GW Wolf Hollow site shortly. The construction cost is estimated at ~$700/kW for these brownfield sites due in part to favorable pricing from GE and cost synergies for Exelon due to the close proximity of the two sites. While ordinarily groundbreaking on a new competitive generation project would hardly be noteworthy, we continue to perceive skepticism from investors regarding the new build activity announced in Texas over the past year given the fall in power and oil prices. While all of the new build may not ultimately materialize, given Exelon's cost advantages, scale, and balance sheet health, we see management as likely to execute. Exelon could also opt to add project financing to enhance financial flexibility. Further details about the units are available in our earlier note, **'Doing the Texas Two Step'**.

Quieting the doubters, EXC has begun construction of its new 2GW capacity in ERCOT.

Unchanged regulated estimates but ExGen weighed down by power weakness

The brunt of the mark-to-market is felt in 2017/2018 where there is less hedge protection. We note that our estimates continue to exclude the EPS contribution from the pending PEPCO deal

Figure 111: Updated Exelon Earnings Estimates

Exelon Consolidated EPS	2014	2015	2016	2017	2018
PECO	0.41	0.43	0.46	0.50	0.55
ComEd	0.47	0.51	0.55	0.60	0.66
BGE	0.23	0.24	0.26	0.27	0.29
Exelon Generation	1.34	1.26	1.11	1.14	0.91
Other	(0.06)	0.00	0.00	0.01	0.02
Total EPS	**2.39**	**2.43**	**2.38**	**2.52**	**2.43**
Guidance	*$2.30-$2.50*	*$2.25-$2.55*			
Consensus	2.40	2.45	2.44	2.62	2.85
Prior UBS estimates	*2.39*	*2.44*	*2.42*	*2.64*	*2.64*
Regulated EPS	*1.11*	*1.17*	*1.27*	*1.37*	*1.49*
Regulated Guidance	*0.95-1.25*	*1.10-1.40*	*1.20-1.50*	*1.25-1.55*	

Source: Company Filings, FactSet, and UBS Estimates

Valuation: Price Target Decreased $2 to $33

We continue to use a 2017E sum-of-the-parts methodology and we have lowered are Price Target by $2. The predominant factor in our reduced price target is the commodity mark-to-market although a contraction in the regulated group multiple also trims some value from the utilities

Figure 112: Updated Exelon Sum-of-the-Parts

All figures in US $ million except per share data		EV/EBITDA & P/E Multiple					Enterprise Value		
	2017 EBITDA	*Low*			*Base*	*High*	*Low*	*Base*	*High*
Generation	1,847	7.0x			8.0x	9.0x	12,931	14,779	16,626
DOE Nuclear Fuel Disposal Fee Uplift	150	5.0x			6.0x	7.0x	750	900	1,050
Hedge Value	(537)	7.0x			8.0x	9.0x	(3,759)	(4,297)	(4,834)
Other/Equity Investments	288	7.0x			8.0x	9.0x	2,016	2,304	2,592
Retail Margin (Power+Non-Power)	536	4.0x			5.0x	6.0x	2,143	2,678	3,214
Total / Implied	2,284	*6.2x*			*7.2x*	*8.2x*	14,080	16,364	18,648
less ExGen net debt (incl PTC/ITC benefits)								(6,807)	
less HoldCo debt								(1,300)	
add Hedge Value								537	
Adding back the FCF drag from Potential Retirements(Clinton, Byron, Ginna, Quad Cities)	164	7.0x			8.0x	9.0x	1,147	1,311	1,475
Equity Value							7,657	10,105	12,553
Mn. Shares Outstanding (2017E)							871	871	871
Merchant Generation Value Per Share							***$ 8.79***	***$ 11.60***	***$ 14.41***
Regulated Utilities			**P/E Multiple**				**Equity Value**		
	2017 Net Income	*Low*	*Peer*	*Prem/ Discount*	*Base*	*High*	*Low*	*Base*	*High*
BGE Net Income	235	12.7x	14.7x	-1.0x	13.7x	14.7x	2,991	3,226	3,462
PECO Net Income	435	13.2x	14.7x	-0.5x	14.2x	15.2x	5,747	6,182	6,618
ComEd Net Income	525	12.7x	14.7x	-1.0x	13.7x	14.7x	6,672	7,197	7,722
Total / Implied	*1,196*	*12.9x*			*13.9x*	*14.9x*	*15,409*	*16,605*	17,802
Implied EPS	*1.37*								
Mn. Shares Outstanding (2017E)							871	871	871
Regulated Utility value per share							***$ 17.68***	***$ 19.06***	***$ 20.43***
Potential Accretion on POM Deal	*EPS*	*Low*	*Peer*	*Prem/ Discount*	*Base*	*High*	*Low*	*Base*	*High*
EPS Accretion (2017 UBSe)	$0.17	13.2x	14.7x	-0.5x	14.2x	15.2x	***$ 2.29***	***$ 2.46***	***$ 2.63***
Total Equity Value per Share							**$ 29.00**	**$ 33.00**	**$ 37.00**

Source: Company Filings, FactSet, and UBS Estimates

FirstEnergy (Neutral; $28 PT)

Is the Analyst Day still on track? Following the recent delay in Ohio the timing could slip to 2016 although mgmt may opt to have a regulated-focused event in the interim. We also look to see how the recent power slump and coal-to-gas trends impact FY16 FES EBITDA guidance; will cost cuts be an offset?

We continue to forecast FE reporting adjusted 2Q15 EPS of **$0.47**, towards the higher-end of management's $0.42-$0.50 guidance range and in-line with consensus ($0.47). We see regulated results increasing by $0.04 due primarily to new Pennsylvania rates effective May 3rd and the impact of the switch to a forward test year at ATSI (without a ROE reduction embedded). FES looks approximately flat YoY and the quarter is pulled down YoY by -$0.05 of higher parent drag.

New PA rates should help FE achieve the upper-half of the guidance but we see the quarter in-line with Consensus.

Figure 113: FE 2Q15 Earnings Walk

2Q14A EPS	**$0.49**
Regulated Utilities (T&D):	
Weather	-
WV: $15Mn Rev Increase	0.00
PA: $293Mn Rev Increase; Rates effective May 3	0.06
JCP&L: -$34.3Mn Rev Decrease effective April 1	(0.01)
Distribution O&M, Pension, D&A, Property Taxes, & Other	(0.04)
Transmission Revenues: Higher ratebase & forward test year	0.08
Transmission Depreciation and Property Taxes	(0.03)
Interest Expense ($600 Mn @ FET and $400 Mn @ ATSI)	(0.02)
First Energy Solutions (FES):	
Lower Retail Sales (20 TWh in 2015, no margin)	(0.02)
Capacity Revenues and Commodity Margin	0.05
Depreciation, O&M, Pension, and Other	(0.03)
Reduced Investment Income	(0.02)
Parent Drag: Tax Rate Normalization-- 33% in 2Q14 vs ~37-38% for this year in 2015	(0.05)
Net Changes	***-$0.02***
2Q15E UBSe EPS	**$0.47**
2Q15 Consensus	***$0.47***
2Q15 Guidance	***$0.42-$0.50***
2015 UBSe	*$2.52*
2015 Consensus	*$2.62*
2015 Guidance	*$2.40-$2.70*

Source: Company Filings, FactSet, and UBS Estimates

For additional context, please refer links to relevant recent reports below:

5/4/15 Carving Out Another Chunk of Change

3/19/15 More March Madness in Columbus

2/20/15 Hitting The Reset Button Again

11/6/14 Can the Coal Comply with the Capacity Scheme

<u>What's new with FE?</u>

Ohio delays have far reaching ramifications on FE's ability to articulate its new regulated story.

- **Ohio PPA procedural schedule delayed:** The Public Utilities Commission of Ohio (PUCO) recently delayed the procedural schedule for FirstEnergy's ESP which likely pushes the timeline for full resolution to 2016 (end of January/early February). Staff testimony is set for August 14th with hearings beginning at the end of August. This delay is not overly surprising following as the new Chairman Porter recently joined the Commission and our conversations with the PUCO indicate that they want to gather as much information as possible (PJM auction results, EPA Clean Power Plan finalize rules, etc.) before progressing too far along in the process.

- **What does this mean for the Analyst Day timing?** We understand that FE has not made a firm decision on when its upcoming Analyst Day will be but the initial plan called for Summer 2015 and now even late 2015 is in question as the Ohio process has developed slower than expected. <u>A 2015 Analyst Day is not off the table but we see the probability as having decreased.</u> *We see delays as negative datapoints to the story for those keen to see a regulated-only growth rate disclosed sooner.* **<u>Why is a delay in the Analyst Day so key?</u>** We see an increasing inflection point around the generation business. If FE does receive a PPA, we see no question around the business' divestment (it *must* remain in order for the PPA to be valid), but the fact that the two issues are tied in our view suggests there could be more of a strategic issue around whether/how FE intends to hold on to FES. Conflicting with the timeline is the annual EEI Financial Conference in November when the company typically rolls-forward its FES unregulated EBITDA guidance where we expect a material decline YoY (transition auctions in PJM could impact this).

- **FE could be one of the biggest winners from the PJM transition auctions:** FE has ~2.8GW of capacity that did not clear in each of the 2016/2017 and 2017/2018 PJM auctions, the bulk of which is the 2.5GW Bruce Mansfield coal plant. FE management disclosed on the 2Q14 earnings call subsequent to the most recent PJM auction that the asset did not clear in the 2017/2018 auction and only partially cleared in the previous 2016/2017 auction. We caution that FE management commentary suggested FES could yet continue to only partially clear its portfolio under the new regime. It will provide an updated maintenance capex outlook for its plants alongside the CP auction results – and corresponding CP bid commitments. We detail the sensitivities below showing our view that FE has the most upside

Figure 114: Estimated EPS/EBITDA Impact for PJM 2016/2017 2017/18 CP Incremental Auctions

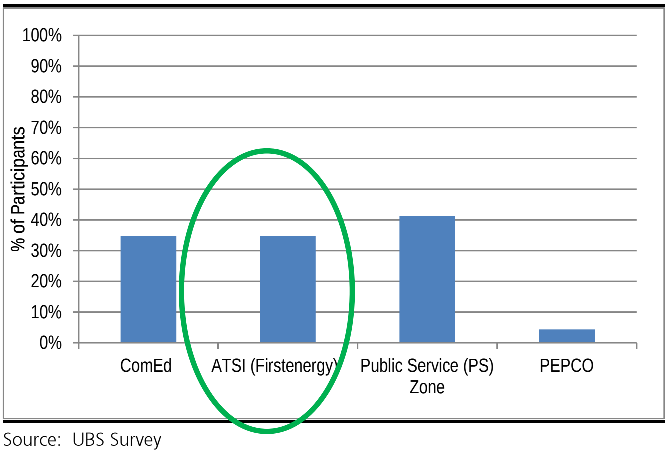
Comparative Impact (EPS & EBITDA)	Total RTO	UBSe 2016 Est	% Impact
DYN (EBITDA)	$ 169	$ 1,395	12%
AEP	$ 0.19	$ 3.69	5%
FE	$ 0.27	$ 2.29	12%
EXC	$ 0.23	$ 2.64	9%
NRG (EBITDA)	$ 113	$ 2,858	4%
AES	$ 0.05	$ 1.42	4%

Comparative Impact (EPS & EBITDA)	Total RTO	UBSe 2017 Est	% Impact
DYN (EBITDA)	$ -	$ 1,395	0%
AEP	$ -	$ 3.69	0%
FE (Includes Uncleared)	$ 0.15	$ 2.29	7%
EXC (Includes Uncleared)	$ 0.12	$ 2.64	5%
NRG	$ -	$ 1.70	0%
AES	$ -	$ 1.42	0%

Source: Company Filings, PJM, SNL, and UBS Estimates

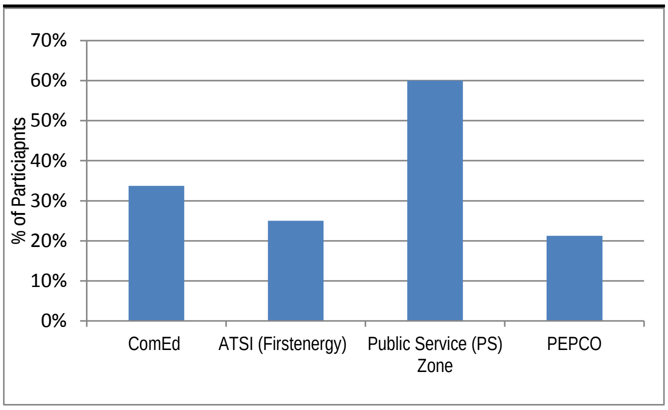
- **Could ATSI breakout in the upcoming auction? Investors see a chance:** In our recent investor/industry PJM survey, the majority of the respondents from both the surveys believe Public Service Zone is the one to break out, while ComEd and ATSI (First Energy) are tied in the second place. The results are in contrast to our view that ComEd appears the most likely zone to price separate. That said, given the wide bidding latitude afforded to participants, we see a bias towards regions breaking out overall. A breakout in the ATSI zone would be a positive for FE's merchant capacity in the region. We temper expectations around PSEG given continued improvements in transmission interconnectivity to adjacent regions. *Some participants in the survey below may have opted not to enter a selection, rather than purposefully suggesting no regions to clear on their own.*

Figure 115: What Regions will Break Out – Investors



Source: UBS Survey

Figure 116: What Regions will Break Out – Industry Participants



Source: UBS Survey

- **More details on cost cutting forthcoming?:** Management disclosed material cost reduction targets with 1Q15 results but was light on details. What we do know is that the cost cuts target the competitive business primarily and are far reaching across the supply chain including fuel/commodities. No headcount reductions are anticipated beyond ~1,000 annually from attrition. Specifically management's initial objective is to save $200Mn run-rate by 2017, split evenly between operating expense and capital expense ($50 Mn for 2015, $150 Mn for 2016). There may also be a small slice of savings coming at the parent level but management emphasized that the regulated growth segments will not be part of the savings review. Excess cash generated by FES will be paid as a dividend to FE Corp. to payback the 2013 $1.5Bn equity infusion which the parent would likely use to reduce the revolver borrowing.

Will we get details on the planned cost cuts?

Target spending reductions:
2015: $50Mn
2016: $150Mn
2017: $200Mn (run-rate)

This is ~half capex/opex.

We give management credit for the FCF benefits of the savings plan through 2017 (collectively $400Mn), but stop short of applying a multiple to this improved profitability noting that (a) it is a combination of capex and opex and (b) it is 'trapped' at FES and is constrained to pay-down the associated debt at the parent.

Figure 117: Select Units Receiving MATS Extensions

Company	Capacity
Duke Energy Corp.	10,168
NRG Energy Inc.	9,911
FirstEnergy Corp.	9,248
Southern Co.	8,825
Texas EFH LP	6,218
DTE Energy Co.	5,824
PPL Corp.	4,134
American Electric Power	3,984
Ameren Corp.	3,339
OGE Energy Corp.	2,561
AES Corp.	2,105
CMS Energy Corp.	2,091

Source: SNL Energy

- **MATS – Do not expect any material change in course on compliance:** The company has estimated $370Mn of MATS spending is required and has completed 40% thus far. We do not anticipate management changing its compliance plans or unretiring units even in the event that MTS is fully overturned by the courts. In 2015E there is $95Mn of capex slated for MATS ($65Mn at regulated/$30Mn at unregulated):
  - **Harrison and Fort Martin:** Estimated compliance costs of $192Mn and FE has already spent $87Mn as of 1Q15 results. These plants are fully regulated.
  - **Bay Shore, Sammis, Mansfield, Pleasants:** Estimated compliance costs of $178Mn and FE has already spent $58Mn as of 1Q15 results. Costs to date for Bay Shore and Sammis are largely complete.

Figure 118: FE Units Receiving MATS Extensions

Plant	MW	Details
Bay Shore ST 1	136	Baghouse Fabric Filter, Mini ACI, CEMS
Bruce Mansfield ST 1 - 3	2,510	WFGD, SCR, CEMS
Fort Martin ST 1-2	1,098	GORE Mercury Control System, Duct Repairs, CEMS
Harrison ST 1 - 3	1,984	Precip, FGD, SCR Catalyst, Duct Repairs, CEMS
Pleasants ST 1 - 2	1,300	Precip, FGD, SCR Catalyst, Duct Repairs, CEMS
W H Sammis ST 1 - 7	2,220	Precip Controls, CEMS

Source: SNL Energy and company filings

- **What about Bruce Mansfield? Still waiting but not related to MATS:** FE has been unable to make a decision on whether it will dedicate the capital necessary to keep its Mansfield coal facility operating but we emphasize that a decision on the dewatering facility is separate from any MATS compliance costs. The necessary capex is estimated at ~$215Mn of capex (2015-2017E) for a new dewatering facility and given the long time frame required to install the environmental facility by YE2016, it is necessary to begin work. A final decision has not yet been made but the decision at least preserves the

Mansfield did not run for six days early in 2015 due to low power prices, leaving uncertainty about mgmt's ultimately determination. Will Capacity Performance be a savior?

optionality heading into the PJM auction later this year. A key to the company's coal outlook is how it will handle coal ash issues for the transition of its Mansfield plant to a different, dry ash site. The retrofits are required by Jan 1, 2017. Installation of the facilities would require temporary mothballing and we ultimately see the investment being made.

- **Creating another TransCo:** FE is further cementing its focus on the utilities by create another transmission company and has requested to move the legacy GPU companies (previous acquisition) into a new entity Mid-Atlantic Interstate Transmission (MAIT) LLC. This would consist of transmission assets from its MedEd, JCP&L, and PennElec subsidiaries. This involves ~$900 Mn in ratebase (~$0.11 in EPS). This will mostly reconcile reporting between the Independent Transmission EPS segment and total Transmission EPS although there are still a few transmission assets at Allegheny with stated (i.e. non-FERC) rates

  - **What is the benefit?** We see accelerated recovery a timing element amounting to ~$0.01-0.02 in 2017. Management estimates that it could have the necessary approvals by mid-2016 from FERC and the states (NJ/PA). We still need to file a section 205 tariff filing driving new ROE and forward-looking rates by end of 2016. This faster recycling of capital could also permit an acceleration of capex deployment for 2017. Depending on the timing of approvals, we could see management revise up its $4.2 Bn capex figure (2014-2017) to reflect ability to fully earn ROE in these jurisdictions through this period. Alternatively, management could also roll-forward this legacy figure to include a *new* year (2015-2018), reflecting higher four-year rolling budget as well.

- **ATSI ROE settlement discussions still ongoing:** We understand parties are *still* continuing to negotiate a settlement around the ATSI proceeding. This could yet be another important datapoint in the continued reductions in ROE – and a leading indicator for MISO, seeing ATSI's 12.38% ROE as legacy to its previous affiliation with MISO.

Reducing our Future Estimates on MtM

We have refined our FirstEnergy solution commodity estimates and performed a mark-to-market; however, we leave our regulated estimates unchanged. As we show in the next Figure, we do not ascribe any value to FES hence the reduced commodity impact does not impact our estimates.

Figure 119: Updated

UBS Adjusted EPS Estimates	2013A	2014A	2015E	2016E	2017E	2018E
Energy Delivery	2.05	1.92	1.82	2.04	2.08	2.17
FirstEnergy Solutions	0.73	0.22	0.47	0.32	(0.28)	(0.25)
Transmission (ATSI, Trail, and OpCo's)	0.51	0.53	0.65	0.74	0.83	0.86
Parent & Other	(0.25)	(0.13)	(0.42)	(0.37)	(0.40)	(0.43)
Total UBSe EPS	3.04	2.53	2.52	2.72	2.23	2.34
Previous UBSe (except Guidance)			2.52	2.74	2.29	2.50
Consensus		*2.50*	*2.62*	*2.67*	*2.49*	*2.75*
Regulated & Parent EPS-Only			2.05	2.40	2.50	2.59
Change			0%	0%	-3%	-6%

Source: Company Filings, FactSet, and UBS Estimates

Valuation: Maintain Price Target

We continue to use a 2017E sum-of-the-parts methodology with our $28 Price Target unchanged. We apply a regulated multiple to the utilities, net of dis-synergies and parent non-interest expense drag. We also deduct the parent obligations.

Figure 120: Updated FirstEnergy Sum-of-the-Parts

FirstEnergy: Sum of the Parts Analysis - Assuming FES Non-Recourse Subsidiary									
Regulated Utilities	2017 Net Income	P/E Multiple					Equity Value		
		Low	Peers	Premium/ Discount	Base	High	Low	Base	High
Core Utilities									
Energy Delivery (FE and AYE Utilities)	888	13.5x	15.0x	-0.5x	14.5x	15.5x	$11,986	$12,874	$13,762
Transmission (ATSI, TRAIL)	352	15.0x	15.0x	1.0x	16.0x	17.0x	$5,280	$5,632	$5,984
Total EPS	*2.91*								
Parent Costs									
Net HoldCo/Parent Expenses (SG&A, etc)	(172)	14.0x	15.0x	0.0x	15.0x	16.0x	($2,413)	($2,585)	($2,758)
Add Back: Parent Interest Expense	128	14.0x	15.0x	0.0x	15.0x	16.0x	$1,798	$1,927	$2,055
Net Parent EPS (SG&A ex-Interest)	*(0.10)*								
Dis-Synergies	*(59)*	13.9x	15.0x	-0.1x	14.9x	15.9x	($820)	($879)	($938)
Total / Implied Utilities	1,137	19.3x			14.9x	22.0x	$16,652	$16,969	$19,044
Total Regulated EPS	*2.67*								
Number of Shares Outstanding - 2017 (Mn)							426	426	426
Regulated Utilities & Transmission Equity value per share							$39.07	$39.81	$44.68
FirstEnergy Solutions (FES): Assuming Non-Recourse Subsidiary							$0.00	$0.00	$0.00
Less: Recourse FES Obligations (Sale Leaseback)								($812)	
Less: Other Parent Sale Leasebacks								($388)	
Less: Parent Notes (12/31)								($4,200)	
Plus: Assumed FES Savings Plan								$400	
Parent/FES Drag per Share								($11.73)	
FirstEnergy Combined (Regulated & FES) Equity Value							$22.50	$28.08	$32.01

Source: Company Filings, FactSet, and UBS Estimates

ITC Holdings Corp (Neutral; $36PT)

Capex risks and FERC related risks to transmission returns remain

We estimate quarterly results of **$0.55** vs consensus at $0.53.Mgmt confirmed nothing unusual in 2Q15, similar to 2Q14. We are below street consensus for the full year however. We continue to assume ROEs for ITC Transmission, METC, and ITC Midwest of 10.84%, which represents a 100bp premium (50bp for RTO participation and 50bp for independence) over our latest FERC mark-to-market ROE of 9.84%.

Nothing unusual this quarter; we expect a beat vs consensus for the quarter, albeit remain below consensus for FY15

Figure 121: ITC EPS Projections

ITC EPS UBSe	2011A	2012A	2013A	1Q14A	2Q14E	2014A	1Q15A	2Q15E	2015E	2016E	2017E	2018E
ITC Transmission	0.54	0.57	0.68			0.71			0.87	0.73	0.74	0.81
METC	0.39	0.46	0.52			0.52			0.65	0.58	0.61	0.67
ITC Midwest	0.49	0.59	0.71			0.72			0.87	0.97	1.22	1.38
ITC Great Plains	0.04	0.09	0.15			0.22			0.25	0.28	0.29	0.31
Parent Drag	(0.36)	(0.32)	(0.41)			(0.31)		0.00	(0.58)	(0.55)	(0.61)	(0.69)
ITC Consolidated	1.10	1.38	1.64	0.44	0.46	1.85	0.47	0.55	2.06	2.00	2.25	2.47
Guidance									*$2.00-2.15*			
YoY Growth		*25%*	*19%*	*18%*	*15%*	*13%*	*6%*	*6%*	*11%*	*-3%*	*13%*	*10%*
Prior UBSe									*2.06*	*2.00*	*2.25*	*2.47*
Consensus								*0.53*	*2.07*	*2.17*	*2.34*	*2.60*
Financial ROE	14.4%	16.2%	17.1%			18.2%			19.8%	18.2%	19.4%	20.1%
ITC 2014-18 CAGR Guidance												11-13%
UBSe CAGR 2014-18 *(Adjusted down for ROE)*												7.4%

Source: Company Filings, FactSet, and UBS Estimates

We recently downgraded ITC (*see: Heading Down the FERC Vortex?*) based on possible future risk to capital structure incentives as applied to transmission companies; the latest change in FERC appears to have a clear pejorative impact on rate treatment. Furthermore, we also see some risk around competition of the Lake Erie project (with uncertainty around counterparty) and ITC's growth capex pipeline.

For additional context, please refer links to relevant recent reports below:
6/10/15 Lining Up Lake Erie
6/2/15 Heading Down the FERC Vortex?
4/1/15 Is The Glass Half Empty?
3/10/15 Rewards Offset the Risks
10/31/15 Focused on Putting Capital in the Ground

Whats the latest at ITC?

- **Lake Erie Open Solicitation process**

As we've noted previously, on May 26, ITC announced it had filed a major permit application with the Canadian National Energy Board for its proposed 1-GW, 73-mile, up to $1 Bn (UBSe) Lake Erie Connector. An open non-binding solicitation is expected to start in late-June and if approved, the line is expected to be in service by 2019. ITC plans to hold an Open Solicitation process in mid-2015, leading to non-binding Expressions of Interest. We look for management to have updates on

We look for management to have updates on contracting success by either 2Q or as late as 3Q

contracting success by either 2Q or as late as 3Q. Below we show critical timelines around the open solicitation:

Figure 122: Lake Erie Open Solicitation process

Date	Description
June 22, 2015	Open Solicitation Commences
August 21, 2015	Deadline for Potential Customers to Submit Expressions of Interest
September 4, 2015	ITC and Brattle Finalize List of Parties for Bilateral Negotiations and Circulate Precedent Agreement
October 15, 2015	Execution of Precedent Agreements
March 31, 2016	Execution of Transmission Service Agreements

Source: Company presentation

- **ROE Case – no major developments yet; resolution likely in 2016**

FERC appears to have set a new 'baseline' ROE for the time being

Mgmt. confirmed there are no additional updates on the ROE complaint cases yet. There are two separate cases lined up here – for the first complaint hearing commence in August, ALJ in November, and a FERC ruling expected sometime next summer; however, there are no firm timelines in place for the second complain.

FERC not going lower than states.

We continue to see FERC transmission ROEs as de-facto set at a *minimum* equal to those established by state jurisdictions in an effort to provide an incentive to pursue more challenged regional transmission projects. This would further lend support to recent ROEs at 9.8% base ROE + 50bp for RTO participation is really the new de-facto floor.

FERC eases concerns NY hypothetical cap structure is one-off

We continue to perceive additional risks around ITC's authorized capital structure beyond wider concerns for continued negative ROE revisions. That said, we see authorized ROE as already broadly known in the market; we already reflect a 10.8% ROE, consistent with recent decisions elsewhere. Rather, we see the ROE risk itself as simply pending, with a protracted timeline to resolution in 2016.

- **Reported Puerto Rico project**

Media reports on May 28 cited a $3.5B partnership between NRG, ITC, and a York Capital Management to bail out the Puerto Rico Electric Power Authority (PREPA). ITC mgmt has not provided any details on this project yet beyond the media reports. As described in the media, the deal would include up to 1,500 MW of CCGTs, 400 MW of solar, and $500M of transmission infrastructure improvements as well as financial support. PREPA would enter into a 30-year purchase power agreement backed by the Government Development Bank. The $500M of transmission and distribution improvements would be implemented by ITC and financed directly by PREPA with another $3B of generation financed by the partnership (presumably structured in tandem with NRG to drop into its YIeldCo structure).

Under an agreement with bondholders, PREPA had until June 1 to deliver a comprehensive recovery plan. While ITC has enough excess funding capacity to finance both this and Lake Erie, we see spending here tied to a longer-dated plan that would likely have the vast majority of spending beyond the scope of the 2014-2018 capital plan.

- **SB 282:** *Putting in place a transmission 'ROFR' for Michigan?*

While not responding to questions around the subject on its 1Q call, we flag potential advantageous legislation to ITC circulating in Michigan around its competitive position in the state. We look for details from management around this in subsequent quarters once past, with the bill still pending before the Senate Energy And Technology Committee.

Valuation: Maintain $36 Price Target

We include our latest ITC valuation, reflecting a 10% probability of a REIT conversion on top of a 1x premium multiple for FERC regulated transmission. The primary question outstanding is whether the changeover in the FERC chairmanship will accelerate the latest negative revisions in authorized ROE?

Price Target $36

ITC Holdings Valuation: P/E Derived on 2017 EPS					
Downside Case		***Base Case***		***Upside Case***	
Valuation		**Price Target**		**Valuation**	
2017 EPS	$1.50	2017 EPS	$2.25	2017 EPS	$2.25
Assumed MISO ROE	9.64%	Assumed MISO ROE	10.84%	Assumed MISO ROE	10.84%
Assumed auth equity	50%	Assumed auth equity	60%	Assumed auth equity	60%
P/E Multiple	14.7x	P/E Multiple	14.7x	P/E Multiple	14.7x
Premium	0.0x	Premium	1.0x	Premium	1.5x
Downside Value	$22.06	Base Value	$35.33	Upside Value	$36.46
REIT Probability	0.0%	Probability	10.0%	Probability	100.0%
REIT Uplift	$0.00	REIT Uplift	$1.06	REIT Uplift	$19.69
Pro-Forma	**$22.00**	**Pro-Forma**	**$36.39**	**Pro-Forma**	**$56.00**
(Downside)	**-39%**	**Upside**	**1%**	**Upside**	**56%**
REIT Scenarios					
Benefit sharing %	100%	Benefit sharing %	50%	Benefit sharing %	10%
Pre-Tax EPS	$1.50	Pre-Tax EPS	$2.93	Pre-Tax EPS	$3.47
P/E Multiple	14.7x	P/E Multiple	14.7x	P/E Multiple	14.7x
Premium	0.0x	Premium	1.0x	Premium	1.5x
Scenario Value	**$22.06**	Scenario Value	**$45.93**	Scenario Value	**$56.14**

Source: Company reports and UBS estimates

NextEra Energy (Buy; $116 PT)

Quarter looks fine but focus will be on how much success NEE has in renewables conversion (a weak spot last quarter). Enhanced clarity on gas reserve investment plans could also be forthcoming

2Q15 should be modestly higher YoY as one-time items at NEER largely washout leaving the Florida utility to grow.

We forecast NextEra Energy reporting adjusted 2Q15 EPS of **$1.52**, a slight beat versus Consensus ($1.47) with large offsetting moving parts at Energy Resources (NEER). The initial weather comparison appears slightly unfavorable but between O&M savings and the depreciation reserve, we see another quarter of solid growth. With $179Mn of depreciation credits remaining, there is wide latitude to achieve the 11.5% ROE (management utilizes the depreciation reserve to 'solve' for a predetermined ROE by applying more credits in the shoulder months). In 2Q14 NextEra recorded $0.15/sh of charges related to the NEP IPO (direct costs and structuring). Other special items present in the comparable quarter include asset sales and 900bp higher than normal wind production.

Figure 123: NEE 2Q15 Earnings Walk

2Q15 YoY Earnings Walk	EPS
2Q14 Adjusted EPS	**$1.43**
Depreciation Credits Remaining ($Mn)	$179
FPL: Earning 11.5% ROE	
Return to Norm weather (+1.9% usage in 2Q14)	(0.03)
Weather in 2Q15	0.01
O&M: Project Momentum	0.01
Depreciation Reserve Amortization	0.01
Riviera (In-Service April 10, 2014)	0.00
Wholesale	0.02
Sales Growth	0.01
Usage	0.01
Energy Resources	
Return to Normal Wind (109% in 2Q14)	(0.09)
NEP IPO Transaction & Structuring	0.15
Asset Sales	(0.07)
Refueling Outage	0.01
Net Investment Growth & NEP min interest (20%)	0.05
Gas Infrastructure	(0.03)
Customer Supply & Trading	0.03
Corp G&A and Other	0.00
Dilution	(0.01)
Change in EPS	**$0.09**
2Q15E	**$1.52**
2Q15E Consensus	*$1.47*
2015 UBSe	*$5.77*
2015 Consensus	*$5.65*
2015 Guidance	*$5.40-$5.70*

Source: Company Filings, FactSet, and UBS Estimates

For more detail on these issues, please see our other recent reports:

Pure Squeezed Sunshine (Analyst day note)
A Shining Star

What's new with NEE?

- **PSC grants the right to let the regulated gas flow:** The Florida PSC voted unanimously to approve the guidelines for FP&L's investment in natural gas reserves with a regulated return profile, one year after management requested approval for investment in the Woodford project ($191Mn estimated NPV). The ongoing parameters allows NEE to invest up to $500Mn per year subject to daily gas burn limits (5% of average daily burn in 2015 rising by 5% annually to 20% in 2018). The PSC will review the program's success after 3-5 years (2018-2020) at which point it could opt to increase or reduce the spending based upon how much customer savings are projected given the commodity environment at that point. This order compares with NEE requesting approval for $750Mn per year and starting the daily gas burn limit at 15% in 2015.

  Management commented that it could take some time to execute on its spending as it looks for attractive opportunities that fit its needs. NEE was likely deliberately quiet on this opportunity while the gas investment potential was then facing judicial challenges but we expect more color with 2Q15 results. Docket: 150001-EI

FL PSC grants approval for $500Mn annual spending on natural gas reserves, subject to gas burn limits.

- **Planned Florida CCGT has no competition:** On July 2nd FP&L announced that it intends to construct the 1.6GW Okeechobee for $1.2Bn ($670/kW) after no external parties submitted complete bids as part of its RFP. At its Analyst Day NextEra expected a $1.0-$1.1Bn cost for the 1,622MW plant with a 6,300 BTU/kWh heat rate. Continuing with its recent strategy, NEE has retained surplus space onsite to potentially add utility-scale solar in the future when the pricing is attractive for customers. Management plans to initiate the regulatory approval process in the near future (14-16 month process) with construction potentially beginning in 2017 with a target commercial operating date of mid-2019.

Planned new CCGT is $200Mn more expensive than view provided at Analyst Day.

- **Intervenors question Cedar Bay purchase:** With the gas ratebasing decision secured, the remaining item to watch at the Florida PSC is the pending docket for FP&L's proposed purchase of the 250MW Cedar Bay plant for $520Mn. The FERC approved the purchase on July 2nd For Cedar Bay a PSC Staff recommendation is expected by August 20th with conference on September 15th and a final order September 21st. Intervenors have challenged the transaction as being too expensive although acknowledge that the proposal would have customer savings. Docket: 150075-EI Areas of issue include:

  - Purchase Price: Office of Public Counsel states that the purchase price is $150Mn higher than market and fails to account for potential environmental liabilities

  - Recovery: NextEra has requested recovery under the Capacity Cost Recovery Clause (CCRC) which would provide a return on the unamortized purchase price at its WACC over the next ten years (life of the PPA). Intervenors have suggested recovery through base rates or with just a debt return.

- **Hawaii merger application to take focus this summer:** The regulatory process for NextEra's pending acquisition of Hawaii Electric is set to accelerate with intervenor testimony slated for July 20th followed by Department of Consumer Advocacy testimony August 10th. NextEra/Hawaii Electric will have until August 31st to respond.

- **Looking to address the Hawaiian spiral:** In the interim, HE has been active with an application to curtail net metering credits for new DG users. The proposal would reduce the net metering rate from the full retail rate of $0.30+/kWh to $0.18-$0.23 depending on the island while increasing the monthly minimum bill to $25 from $17-$20.50, again depending on the specific island. All current net metering customers and those with valid applications would be grandfathered under the existing regime.

- **Eyes on the renewables pipeline:** We expect that management will add additional wind to its pipeline for YE16 COD to fill the 900-1,100MW '15/'16 pending. Following 1Q15 results shares were weak and we attributed that to a lack of conversions at the time. Unlike renewable development peers, NEE is more conservative both operationally and when it comes to sending messages to the Street. Between the Analyst Day and April earnings management converted ~500MW of renewables from its 2015-2018 pipeline forecast into its NEER backlog (to 2.6GW from 2.1GW) with the total origination platform backlog/pipeline midpoint unchanged at 4.9GW. The lack of new pipeline additions is driven by an abundance of caution. Unlike renewable development peers which probability weight opportunities, management opts for a conservative approach. Bottom line, more renewables are coming and we see NextEra as well positioned to capture the opportunities. We see opportunities around Ontario solar, wind, and storage as particularly intriguing.

Figure 124: Recent Changes in NEER's Backlog and Pipeline

Update Date	Backlog	2015-2016F	2017-2018F	Total
1Q15	2,616	1,000	1,250	4,866
Investor Day	2,114	1,400	1,350	4,864
Change	502	(400)	(100)	2

Source: Company Filings and UBS Estimates

Looking at NEE through the DevCo valuation of SUNE

In contrast to our valuation for SunEdison, we conservatively do not ascribe a benefit for the developer margin that NEE generates. Assuming 2.0GW per annum, of development at ~$1.50/watt with a 15% EBITDA margin would imply $5/sh of total value. Since NEE holds its renewables on its own balance sheet for a longer period of time than solar rivals do, we ascribe an EV / EBITDA multiple on the cash flows rather than an explicit DevCo multiple. Further we ascribe in our existing SOP for the 'Pipeline' value of $3/sh, this more solar-oriented valuation would have a further $2/sh uplift on our existing $116/sh target.

Figure 125: How Much Value from DevCo Valuation Approach?

DevCo Margins for NEER		
Annual Build	**2,000**	**MWs**
Build Cost	1,500	$/kW
Total Dev Cost	3,000	
Dev Margin %	15	%
Dev Margin ($ Mn)	450	
EV/EBITDA on DevCo	5	x
Value Uplift	**2,250**	**$ Mn**
Value Uplift per Share	**4.85**	**$/sh**
Dev Pipeline value in our SOP	2.98	
Incremental Value Uplift	1.86	

Source: Company reports and UBS estimates

- **Regulated M&A – After Hawaii is Oncor Next?:** Some investors we speak with continue to maintain a negative view of the pending Hawaii Electric transaction given the lack of initial accretion on the price paid. We reiterate that we do not include any incremental from the Hawaiian deal in our valuation as our initial analysis showed approximately breakeven economics. We acknowledge that there are potential upside levers which could improve the upside for the deal but our bullish viewpoint on NEE is not contingent on improvement in HE.

  - **With respect to Oncor we see this deal as unlikely for NEE**. Per the Wall Street Journal (6/26 'Energy Future Scraps Oncor Bankruptcy Auction') Energy Future Holdings Corp notified the Bankruptcy Court requesting to termination of the auction process for its ownership stake in the T&D utility Oncor. We see the latest rejection of the Oncor auction process as a negative for NextEra Energy which has publicly expressed interest in the past. The question now reverts to what other candidates might management be interested in as NEE has been involved in M&A (current pending Hawaii Electric deal) and has surplus cash flows from its NEP YieldCo guided dropdowns? A delay in a regulated transaction would also put the brakes on management's ability to deploy capital into more risky midstream ventures with a higher risk profile (for instance, G&P).

We see the latest developments as firmly setting back management's latest strategic ambitions

    We would not rule-out further M&A and see this as one of the clearest avenues for management to deploy its cash from NEP recycling (drop-downs and IDRs). There are three

(1) O&M Synergies: Management emphasized opportunity to find less efficient utilities, leveraging synergies to improve the earned ROE of any target. Given the wide disparity in the efficiency metrics across utilities of different sizes, we see NEE as looking for an opportunity where it can excel in reducing the cost structure.

(2) Parent re-leveraging: Any deal would accompany substantial incremental leverage to maximize the value proposition. A primary reason why the HE deal was a share-for-share transaction was a desire to make the transaction tax-free for HE shareholders. NEE could repurchasing shares and essentially lever up the deal, a

playbook we would expect to see followed in any future NEE transaction.

(3) Parent credit quality halo: Secondary effects including supporting the parent credit rating for further infra investments. Mgmt emphasized further regulated acquisitions could allow it to diversify into high-risk infrastructure investments like Gathering & Processing.

Estimates slightly lower for MtM

Our estimates have been updated for the commodities mark-to-market which resulted in an immaterial negative change.

Figure 126: Updated NextEra Energy Estimates

EPS - Segments	2013A	2014A	2015E	2016E	2017E
FP&L	3.16	3.45	3.24	3.44	3.71
NEER	1.83	1.89	2.40	2.47	2.63
Corporate & Other	(0.02)	(0.04)	0.07	0.14	0.16
Total UBSe	4.97	5.30	5.71	6.05	6.49
UBSe (Prior)	4.97	5.30	5.72	6.06	6.53
Consensus (7/6/15)		5.30	5.65	6.08	6.44
Company Guidance		5.15-5.35	$5.40-$5.70	5.75-6.25	

Source: Company Filings, FactSet, and UBS Estimates

Valuation: Reduce Price Target $2 to $116

We continue to use a 2017E sum-of-the-parts methodology and the $2 reduction in valuation is driven by a small contraction in the peer multiple as well as weaker commodity prices.

Figure 127: Updated NextEra Energy Valuation

	2017E Adj. EBITDA	EV/EBITDA & P/E Multiple			Enterprise Value		
Energy Resources		**Low**	**Base**	**High**	**Low**	**Base**	**High**
Traditional Generation	928	8.0x	9.0x	10.0x	7,422	8,349	9,277
Wind (Total)	1,300	11.0x	12.0x	13.0x	14,301	15,601	16,901
Hedges (Texas 'Merchant' Wind)	(81)	11.0x	12.0x	13.0x	(888)	(969)	(1,050)
Tax Credits (PTC)	1,055	7.0x	8.0x	9.0x	7,384	8,439	9,494
Less NEP Initial Wind Assets	*(175)*	*11.0x*	*12.0x*	*13.0x*	*(1,928)*	*(2,104)*	*(2,279)*
Solar (Total), excl ITC	324	11.0x	12.0x	13.0x	3,563	3,887	4,211
Less NEP Initial Solar Assets	*(88)*	*11.0x*	*12.0x*	*13.0x*	*(963)*	*(1,050)*	*(1,138)*
Gas Infrastructure	379	6.0x	7.0x	8.0x	2,276	2,656	3,035
Trading & Retail	137	4.0x	5.0x	6.0x	546	683	819
Total / Implied (ex-ITC)	***3,779***	***8.4x***	***9.4x***	***10.4x***	***31,713***	***35,492***	***39,271***
Add: Silver State Solar NPV						**583**	*$1.26*
Add: NPV Sabal Trail, SE Connection, and Mountain Valley Project						**2,040**	*$4.39*
Add: NPV of Remaining Solar and Wind Project Pipeline						**1,385**	*$2.98*
Add: NPV of Texas Hedge						**323**	*$0.70*
Less: Total NextEra Debt						(29,334)	
Netting FP&L-associated debt						8,797	
Netting NextEra Transmission-associated debt						411	
Netting Pipeline debt						-	
Netting NEP Debt						*1,655*	
Net NEE Resources Debt						**(18,471)**	
NextEra Energy Resources					**13,242**	**21,353**	**22,840**
Shares Outstanding (2017E)					464	464	464
NextEra Energy Resources Value per Share					**$28.52**	**$45.98**	**$49.19**

	2017E NI	P/E Multiple							
		Low	**Peer**	**Prem/ Discount**	**Base Multiple**	**High**			
Florida Power & Light	1,723	15x	14.7x	1.0x	15.7x	17x	25,326	27,049	28,771
NextEra Transmision	34	15x	14.7x	2.0x	16.7x	18x	500	568	602
Total Utility	***1,757***	***14.7x***			***15.7x***	***16.7x***	***25,826***	***27,617***	***29,374***
Shares Outstanding (2017E)							464	464	464
NextEra Utilities Value per Share							**$55.62**	**$59.47**	**$63.26**
Value of the NEP GP per Share (IDRs)							$2.70	$3.70	$4.70
NEP Price Target							$30	$44	$55
Value of NEP LP per NEE Share based on NEP Price Target							$4.81	$7.06	$8.82
NEP Value per Share							**$7.51**	**$10.75**	**$13.52**
Total Equity Value per Share							**$92.00**	**$116.00**	**$126.00**

Source: Company Filings, FactSet, and UBS Estimates

NRG Energy (Buy; $25PT)

Could volumes disappoint here?

We forecast NRG reporting adjusted 2Q15 EBITDA of **$664Mn**, essentially in-line with consensus ($676Mn), due to broad based weakness. In particular we see risk for a meaningful reduction in YoY retail volumes given disappointing weather in the quarter, notably in Texas, the center of its retail operations. We estimate declines in most major markets as hedges continue to rolloff.

Guidance range appears safe although the top-quartile of results may be hard to hold given weak weather.

As for FY15 Guidance, the question remains to what extent expectations will be revised down from the top quartile of its range ($3.2-3.4Bn). We suspect a strong hedged position will continue to support results, but we're revising down our estimates closer to the midpoint of the range (~$3.3Bn) to reflect potential for weaker retail sales.

Figure 128: NRG 2Q EBITDA Comparison

NRG Energy Adjusted EBITDA ($Mn)	1Q15A	1Q14A	1Q +/-	2Q15E	2Q14A	2Q +/-	UBSe FY15	NRG 2015 Guidance *	2014A
Wholesale - Total	674	708	(34)	530	498	32	2,662	2,625-2,750	2,524
Retail Businesses	166	108	58	134	173	(39)	626	575-650	604
Adjusted EBITDA	**840**	**816**	**24**	**664**	**671**	**(7)**	**3,288**	**3,200-3,400**	**3,128**
Street Mean EBITDA Est.				*676*			*3,297*		

Source: Company reports, ThomsonReuters, and UBS estimates

For additional context, please refer links to relevant recent reports below:

5/27/15 Paving the Road with Solar
5/12/15 Let the Summer of Repurchases Commence
2/27/15 Splitting The YieldCo
1/20/15 Picking Apart The Solar Opportunity
1/16/15 Daring to Dream

Key Issues for NRG Energy

Framing the NRG Home Restructuring Debate

NRG may be contemplating *another* spin, eventually?

In recent weeks there has been substantial discussion around NRG's corporate strategy in an effort to better reflect the underlying 'Sum of the Parts' value embedded within the company. We see a wider focus around capturing the premium value of the NRG Home suite of businesses, following the realignment of business units coincident with its Analyst Day earlier this year. While it appears there are a variety of permutations at play, we see this as motivated by similar factors behind the success of NRG Yield to realize multiple expansion and reduce underlying volatility in valuation.

- **Realizing the resi solar company stand-alone valuation:** We believe the key motivating factor is extracting comparable value of SolarCity (SCTY) and Vivint (VSLR) into NRG's still nascent Home solar efforts. We see NRG as keen to garner the premium multiples on these retail solar companies back to its efforts.

How do we currently value the NRG Solar business?

We presently ascribe **~$2/sh** in our SOP predicated on hitting its 250MW residential target for year-end, rather than the **~$5/sh** implied by looking at peer valuations.

Figure 129: NRG Existing SOP Valuation Today (Left) vs. Implied from Peer Comps (Right)

2015 Solar Targets	
Residential (NRG Home)	
250	MW
16	CAFD (c/Watt)
40	CAFD Equivalent (pre-leverage)
10%	Monetization Yield
400	EV to NRG
1,250	*Upside EV Scenario to 5x 2015 MW Target*
Commercial ('Distributed Generation' per NRG Disclosures)	
191	MW
11	CAFD (c/Watt)
21	CAFD Equivalent (pre-leverage)
9%	Monetization Yield
233	EV to NRG
633	Total Solar EV to NRG
317	Shares Outstanding ('15e)
2.00	Total Solar EV to NRG, per Share

Valuation on per/MW Basis	
SCTY	
920-1000	2015 Target (MWs)
960	Midpoint MWs
505-520	2014 Target (MWs)
512.5	Midpoint MWs
52.27	Share Price
96	Shares Outstanding
263	Debt Outstanding (per 3Q 10Q)
5,281	EV (excluding Tax Equity)
10.30	EV/2014 MWs
5.50	EV/2015 MWs
VSLR	
224	2014 Target MWs
10.94	Share Price
105	Shares Outstanding
146	Debt & Capital Lease Outstanding (per 3Q 10Q
1,295	EV (excluding Tax Equity)
5.78	EV/2014 MWs

Source: Company reports and UBS estimates; excludes convert dilution, tax equity, and ABS issuances for VSLR and SCTY

Please refer to our previous note at the time of the Analyst Day in January contrasting **NRG's solar efforts** to SCTY and VSLR, for the base of the above two tables.

- **Breaking apart the retail business?** Among the core elements of any potential spin of NRG Home, would be a need to retain the core cash flows associated with the retail business, which remain substantial, and provide the bulk of the cash flow to NRG Classic. We don't see a spin of any of these cash flows as palatable seeing the associated cash flow volatility and earnings. Notably, management presented the total 'opportunity' for the retail business to exceed $1 Bn, off the $615 Mn guidance in 2015 by 2022, primarily driven by complementary sales.

- **Does this actually bode well for a higher multiple on its retail biz?** While this debate has been dormant for some time, we continue to apply a modest 5x EV/EBITDA in our valuation SOP to the aggregate retail platform. With many having historically argued the integrated nature of the retail platform, along with an exceptionally sticky customer base, could argue for a better multiple (particularly when contrasting against its Texas IPP peer, EFH, which has historically traded as a fully integrated EV/EBITDA multiple).

- **If the retail business doesn't 'go with the spin': a cross-marketing deal is necessary.** NRG's “secret sauce” in the solar business appears to be leveraging the infrastructure for both customer acquisition as well as customer service offered by NRG's existing retail footprint. Negotiating deals to maintain these benefits for any spin would prove vital. We further emphasize that NRG has indicated that it would eventually seek to 'drop-down' (sell) any of its successful

residential solar projects down into the YieldCo structure making NRG Home spin really a focus on development than long-term ownership (effectively lead generation in our view). The question is whether any NRG Home business would continue to feed into the NYLD YieldCo structure as well? Likely yes.

- **Solar can't necessarily be a FCF negative company and spun-out:** Given the negative EBITDA associated with this business (excl from guidance), we see a need to achieve critical mass and sufficient cash flows and liquidity to stand alone as a company.

- **Proving out the solar business is key.** We believe one of the key issues for shares as it relates to the projected improvement in solar market share implied by its figures. We believe many solar investors fail to appreciate NRG's incumbent position to cross-sell solar energy across the less known Northeast markets. *We see execution on even just NRG's base plan will afford substantially greater credibility with solar investors – and put it rapidly on the map vs. existing large-scale peers.*

- **Does this create ongoing value for NRG shareholders?** While we see NRG Yield as an unambiguous success, some NRG shareholders have previously asked whether any benefits were ultimately realized by NRG from its spin. In turn, we believe shareholders will ask many of these same questions in the current instance. Bottom line yes, the question is simply how much? We argue $2-3/sh initially.

- **Timing is likely 2016 earliest.** We still see any developments as very much preliminary. We see a need to first prove out the business, and generate cash flow on its own to make this arrangement work.

- **What *else* could be included: EVGo, etc?** Beyond a focus on the NRG Home solar opportunity, the question remains whether other 'peripheral' businesses would be contemplated in any spin – eventually. We see the EVGo as perhaps a bit early in its life to contemplate any meaningful contribution, but could well complement any NRG Home offering down the line.

Diving into the Cash Flows: We estimate a ~15% avg FCF yield ex-NYLD

Figure 130: NRG and GenOn Free Cash Flow Analysis

EBITDA to Cash Flow Analysis	2014	2015	2016	2017	2018	2019
NRG:						
EBITDA	3,128	3,288	2,953	2,706	2,730	2,855
Interest	(1119)	(1,084)	(1,060)	(1,021)	(981)	(840)
Income Tax	7	(50)	(50)	(50)	(50)	(50)
Collateral / Working Capital	(320)	(70)	41	31	(305)	(16)
Other / Deferred Taxes	(186)	-	-	-	-	-
CFO	1,510	1,947	1,815	1,695	1,398	1,883
Maintenance Capex	(254)	(540)	(475)	(375)	(375)	(375)
Enviro Capex	(254)	(300)	(250)	(5)	(15)	(20)
Pfd Div	(9)	(9)	(9)	(9)	(9)	(9)
FCF Pre-Growth Capex	993	1,098	1,081	1,306	999	1,479
Guidance		*1,100-1,300*				
CAFD from NYLD		(234)	(305)	(355)	(358)	(363)
Amortization Schedule - Non-NYLD						
Agua Caliente		28	29	30	31	31
CVSR		25	25	26	27	28
Viento		22	23	23	24	25
NRG Peaker		20	20	20	20	21
Cedro Hill		8	9	9	9	9
NRG - Other		19	19	20	21	21
Debt Amortization		121	124	128	132	135
Less: Non-Owned Distributable Cash flow from NYLD	(57)	(105)	(137)	(160)	(161)	(163)
Less: Other	15					
FCF net of NYLD and Debt Amortization	951	992	943	1,146	838	1,316
Plus: Non-Cash Lease Amortization		80	80	80	80	80
Less: Minimum Lease Payment		(166)	(211)	(207)	(196)	(195)
Adjusting for GenOn Leveraged Leases		(86)	(131)	(127)	(116)	(115)
Market Cap		7,257				
Less NYLD Stake		1,783				
Market Cap (ex-NYLD)		6,414				
FCF net of NYLD, Debt Amort, and Leveraged Leases		906	812	1,019	722	1,201
Implied FCF Yield (with NYLD)		12%	11%	14%	10%	17%
Implied FCF Yield (without NYLD)		14%	13%	16%	11%	19%
GenOn EBITDA		542	364	298	333	353
Interest Expense		(262)	(262)	(262)	(282)	(302)
Maintenance Capex		115	110	115	115	115
Environmental Capex		7	-	-	-	-
Total Capex		122	110	115	115	115
Free Cash Flow (Pre-Leveraged Lease)		157	(8)	(79)	(65)	(64)
Net Leveraged Lease Impact (Debt Amort)		(86)	(131)	(127)	(116)	(115)
Free Cash Flow (Pre-Leveraged Lease)		71	(139)	(206)	(181)	(179)
FCF net of NYLD, Debt Amortization and GenOn		1,150	935	1,067	773	1,252
FCF net of NYLD and Debt Amortization (without GenOn)		992	943	1,146	838	1,316
Uses						
Organic Growth Capital		900	500	500	-	-
Total Capex		1740	1,225	880	390	395
Assumed Share Repurchases		437	-	-	-	-
Projected Common Dividend		184	184	184	184	184
Remaining for Debt Paydown, etc.		(1,263)	(328)	242	425	901

Source: Company Filings and UBS Estimates

Other Focuses

- **MATS Impact? It's not quite clear.** We look for management to provide an update on its portfolio given the latest developments at the Supreme Court; we largely understand there will be no change to compliance strategies *even* in the event if the rules are vacated. We suspect no decision from the DC Circuit court in time to reflect retirement expectations for upcoming PJM transition auctions.

- **Could it scale back investments on plants remaining open?** In the event of vacatur, we would not doubt some scaling back on usage of expensive TRONA, and other DSI technologies at its legacy GenOn and EME portfolios.

- **Coal to gas impacts?:** The question remains how this could yet play out for NRG in 2015, both for its GenOn subsidiary as well as NRG Classic portfolio. We see recent pullback in the PRB deliveries, particularly exhibited by BN in 2Q coal volumes, NRG's primary rail shipper as indicative of this risk. Again, we emphasize a decline in delivered volumes is offset substantially by pre-existing hedges.

- **Execution on Coal to gas conversions a focus too?** Meanwhile, we look for the latest on execution of its contemplated conversion of the Avon Lake facility given local opposition here too to the installation of the gas lateral. This too appears to be a growing risk to the GenOn projected EBITDA. As a reminder, many of these conversions are slated for Summer and Fall 2016.

NRG: Ivanpah faces operational challenges pains but still very early

Despite operational initial teething issues, full operations remain ~2-year away

The Wall Street Journal released another article on June 12th ('High-Tech Solar Projects Fail to Deliver') regarding NRG's jointly-owned Ivanpah solar thermal asset in California as investors continue to question the technology in the face of solar PV's declining cost curve. The WSJ previously called the asset the "$2.2 Billion Bird-Scorching Solar Project" and continues to focus on the performance to date that has not met initial projects. Ivanpah is one of the world's largest concentrating solar power (CSP) assets and was projected to generate 940,000MWh annually but only generated 419,000 in 2014 (45%). The asset is jointly owned by NRG (50%), Google (28%), and BrightSource (22%) with $1.6Bn of Title XVII federal loan guarantees. NRG has applied for $581Mn of cash grants for Ivanpah and has received $485Mn and has $1.2Bn of Ivanpah financing outstanding.

Following our latest review of Ivanpah's disclosures we have reduced our **near-term** adjusted EBITDA and CAFD estimates. Specifically we adjusted two assumptions:

- **Reduced capacity factor to 15% from 27%:** In 2014 the capacity factor was 12.2% and was approximately 15% in the first quarter of 2015. Our original estimate of 27% was consistent with 940,000MWh expected generation. This 45% reduction in our generation estimate is consistent with the shortfall in 2014 vs the originally projected generation. We maintain our capacity factor assumption in the longer-term at 27% reflecting full operations are achieved.

- **Increased O&M per kW-year to $75 from $64:** The higher cost structure is driven almost entirely due to fuel costs which totalled nearly $4Mn in 2014 ($9/MWh). The WSJ reports that the unit requires four hours of natural-gas each morning to support operations.

We caution that it is likely too soon to take such a punitive view on the asset on a **longer-term** basis as management has stressed that it originally contemplated a ~four year process to bring the asset up to full capacity and it is not yet halfway into that timeframe. While we are concerned, we take additional comfort in the fact that NRG Energy does have assets that it can drop into NRG Yield in the interim and still has years before it will likely sell the asset to NYLD.

What's the risk? How much CAFD will it generate.

The development issues are primarily a risk for NRG parent, rather than NYLD, and will ultimately determine the drop-down multiple. Given the magnitude of debt, the multiple would have to be quite healthy with a lower cash flow profile.

Figure 131: Ivanpah 2014 Snapshot

Ivanpah 2014 Snapshot				
	Unit 1	Unit 2	Unit 3	Total
Capacity	125	133	133	391
Capacity Factor (%)	13.9%	11.1%	11.8%	12.2%
Generation (MWh)	151,966	129,263	137,856	419,085
Fuel Cost ($Mn)	1	1	1	4
Fuel per MWh	8.3	10.0	8.9	9.0
Fixed O&M ($Mn)	9	9	9	28
Fixed O&M per MWh	57.9	72.4	67.9	65.7
Fuel + O&M ($Mn)	10	11	11	31
Fuel + O&M per MWh	66.2	82.4	76.8	74.7
UBSe	**Updated**	**Previous**		
O&M ($/kW-yr)	$75	$64		
Capacity Factor (%)	15%	27%		
EBITDA	$30	$68		
CAFD	$7	$26		

Source: Company Filings, SNL Energy, Department of Energy, and UBS Estimates

Why are we so focused here? Others are having issues.

Abengoa and Abengoa Yield also have exposure to solar thermal with Abengoa Solar advertising proprietary technology. Abengoa Solar operates the Solucar Complex (PS10 & PS20) in Spain which represents 31MW of capacity but there are aspirations to add more.

In September Abengoa S.A. purchased BrightSource Energy's 50% ownership in the Palen Solar thermal development project for an undisclosed amount. The Riverside California asset has faced pushback from the California Energy Commission on various fronts and was ultimately approved in a scaled down form (250MW with one power tower vs 500MW with two power towers previously). Following the scrutiny on Ivanpah, it remains to be seen whether Abengoa will ultimately continue with the development plan; however, Abengoa has disclosed that it plans some changes to the project such as adding storage and reliance on its own technology. BrightSource previously disclosed that the project was unlikely to qualify for ITCs given its 28-month construction cycle.

Among the pieces of NRG story, we see NYLD as having limited upside

Seeing risks associated with Ivanpah operational execution as well as a limited utility-scale effort in either contracted wind or solar, we continue to expect an

eventual slowing of its growth rate. As such, we see an argument for the more development-oriented solar companies to potentially surpass NYLD as 'premier' YieldCo's in the sector.

Can NRG Solar save the day? Only a modest contributor

While we see the development of a Residential and C&I solar effort as an excellent source of multiple uplift for the overall company, we see this strategy as limited in terms of total asset contributions. Management's guidance net of leverage for NYLD by 2019 is just $70 Mn for the resi business and $35 Mn for the C&I (DG) business. We see this as amounting to effectively just one large utility-scale project, and indicative of a clear slowing trend. For example, currently NRG's ROFO pipeline beyond 2015 includes just a $250Mn equity investment for residential and other DG solar portfolios coming online after this year. In contrast management has guided to ~$350Mn of gross CAFD for all of its non-distributed solar assets.

NRG Yield M&A merits some attention

Following NRG's latest acquisition of GE EFS' interest in the Desert Sunlight project in California (a FSLR built project), we look for commentary from NRG around the outlook for future for further such deals following suggestions that recent third-party transactions in the wind sector were too expensive for NRG.

Below we include an analysis on NYLD's recent Desert Sunlight acquisition, showing an implied CAFD yield of 7.7%, generally lower than what we've seen of recent comps. In contrast, recent deals have been in the ~9% range. This PPA was signed in 2010 (estimated at $150/MWh) at a significantly higher price than what is seen today, providing some element of contract risk at expiration (25-year tenor). We see this deal as rivalling TERP's latest Invenergy wind acquisition at an 8.4% levered yield as among the tightest thus far, continuing to illustrating the market highs for renewable assets.

Figure 132: NYLD Desert Sunlight Economics Breakdown

Desert Sunlight (NYLD from GE, June 2015)	
Income	
EBITDA	45
Cash Flow Available for Distribution (CAFD)	22
Capitalization	
Assumed Debt	287
Equity Paid	285
Total Price	572
Implied CAFD Yield	7.7%
EV/EBITDA	12.7
Capacity (MWs)	138
Implied Equity $/Watt	4.16
Implied EV $/Watt	2.07
Capacity Factor	27%
GWh	325.22
O&M ($/kW)	30
O&M ($ Mn)	4.13
Rev ($ Mn)	49.13
Implied PPA Price ($/MWh)	**151.05**
PPA Vintage	CPUC 2010

Source: Company Filings, UBSe

EBITDA Estimate Update Mixed on Hedges

Our updated estimates reflect our latest mark-to-market which has a clear negative bias on our estimates. We caution that following management's latest financial reporting alignment, there is less transparency into the wholesale sub-segments (collectively classified within 'NRG Business').

Figure 133: Updated NRG Energy Adjusted EBITDA Estimates

EBITDA ($Mn)	2013A	2014A	2015E	2016E	2017E	2018E
NYMEX Assumption		*4.26*	*3.19*	*3.19*	*3.37*	*3.50*
Texas	502	302	415	227	115	103
Northeast	1,004	1,206	775	650	524	562
South Central	43	118	94	85	107	144
West	167	272	385	373	385	320
Alt Energy & NYLD	335	627	601	638	634	632
Guidance			690			
Retail Businesses	614	604	626	588	554	583
Guidance			575-650			
Corporate, Other, and Unallocated Synergie	(29)	(1)	393	392	387	387
NRG Adj. EBITDA (UBSe)	2,636	3,128	3,288	2,953	2,706	2,730
Prior EBITDA Est. (UBSe)		3,128	3,368	3,096	2,858	2,848
Consensus EBITDA Est.(7/13/15)	2,636	3,194	3,297	3,103	2,932	
Guidance (1Q15)	2550-2600	$3,100-$3,200	$3,200-$3,400	Upper Quartile		

Source: Company reports, ThomsonReuters, and UBS estimates

Valuation: Reduce Price Target $5 to $25

Our valuation is based on 2016E sum-of-the-parts. Although we are reducing our price target on the back of lower power prices, we still see value in shares. Aside from the obvious potential recovery in power prices and upcoming PJM capacity market datapoints, we see upside to our valuation at the Home Solar subsidiary where we reflect just $2/sh for the near-term targets. A potential offset is that we still value GenOn at ~$2/sh despite the challenged free cash flow profile and concerns about the expected economic life of some underlying units.

Figure 134: Updated NRG Energy Sum-of-the-Parts

All figures in US $ million except per share data	2016 EBITDAR	EV/EBITDA Multiple			Enterprise Value		
NRG Energy (Classic) and GenOn		Low	Base	High	Low	Base	High
Texas	227	8.0x	9.0x	10.0x	1,817	2,044	2,272
Northeast	493	8.0x	9.0x	10.0x	3,947	4,441	4,934
GenOn Operating Leases	80	8.0x	9.0x	10.0x	640	720	800
South Central	85	8.0x	9.0x	10.0x	681	766	851
West (ex-EME)	140	7.0x	8.0x	9.0x	982	1,123	1,263
Alt Energy (ex-NYLD and EME Portions)	163	11.0x	12.0x	13.0x	1,792	1,955	2,117
Retail Businesses (Reliant, GM, E+, Ex-Dominion)	588	4.0x	5.0x	6.0x	2,351	2,938	3,526
Edison Mission							
EME - MidWest Generation	127	8.0x	9.0x	10.0x	1,013	1,140	1,266
EME - EMMT (Trading)	32	4.0x	5.0x	6.0x	126	158	189
EME - NYLD (Wind)	65	11.0x	12.0x	13.0x	715	780	845
EME - Other (Gas and Other)	66	8.0x	9.0x	10.0x	528	594	660
Other, Corporate, and Unallocated Synergies	375	4.0x	5.0x	6.0x	1,498	1,873	2,247
Total / Implied	2,440	6.6x	7.6x	8.6x	16,090	18,531	20,971
Net Debt and Other							
NRG Recourse Debt						(8,800)	
GenOn Non-Recourse Debt						(3,122)	
GenOn PV Operating Leases						(1,326)	
Midwest Gen Compliance Plan						(545)	
Solar Non-Recourse Debt (Non-NYLD)						(1,699)	
NPV of Solar Accel Depreciated Tax Benefits (Upside with EME wind PTCs?)						653	
Preferred Shares (2015E)						(310)	
Cash (2015E)						2,859	
Add: NRG Yield Home Solar Opportunity (~400MW @ 13¢/watt; 13x CAFD)						633	
NPV of Equity using Hedged EBITDA Methodology					4,433	6,874	9,314
Open Analysis							
Power Hedges	(419)	8.0x	9.0x	10.0x	(3,350)	(3,768)	(4,187)
Coal Hedges	4	8.0x	9.0x	10.0x	36	40	45
Total	(414)	8.0x	9.0x	10.0x	(3,314)	(3,728)	(4,142)
add NPV of Power Hedges						1,294	
add NPV of Coal Hedges						(25)	
NPV of Equity using Open EBITDA Methodology					2,388	4,414	6,440
NYLD -> UBS Price Target					22.00	27.00	32.00
NYLD Equity Value					939	2,306	1,366
$/share for NRG Energy (85Mn Shares Outsanding)					2.97	7.28	4.32
Projected Shares outstanding					317	317	317
Equity value per share (using Avg of Open/Hedged)					$14.00	$25.00	$29.00

Source: Company Filings and UBS Estimates

PG&E Corporation (Neutral; PT $54)

Expect a dime beat on non-recurring 2014 GRC cost recovery offset by unrecovered GT&S costs due to the ongoing ratecase delay.

On guidance, it is unclear at this time how management will continue to treat existing guidance given the latest delay for the GT&S ratecase.

We expect a dime beat for 2Q15 at **$0.83** vs consensus $0.72, with much of the beat caused by delayed electric GRC expense recovery last year offset by the effect of the ongoing delayed Gas Transmission and Storage (GT&S) ratecase this year. Unrecovered 2014 costs in 1H14 cause a +$0.21 year-over-year comparison in 2Q15, similar to both the 4Q and 1Q comps. As broken out in the table below, this is made up of about $0.08 of 2014 expense recovery, $0.06 of 2014 repairs tax benefits (and forecast change), $0.05 of 2014 ratebase growth, and $0.02 of other delayed recovery items. Note that in 3Q, we expect all of these items to be significantly negative year-over-year (about -$0.39) as a result of a 1x catchup in 3Q14. For 2015, continued ratebase growth helps another +$0.05, similar to the 1Q yoy comp. In this year's delayed GT&S case, the company requested a $555M rate increase, roughly a 76% increase if granted in full. Rough guidance for unrecovered expense is about $0.60 for full year 2015, with seasonality a factor for each quarter (we assume a -$0.10 yoy impact for 2Q vs -$0.08 in 1Q). On 2015 taxes, there is a timing issue, with +$0.04 in 1Q15 expected to reverse out to zero impact by the end of the year (i.e., about -$0.0133 in 2Q, 3Q, 4Q). The sale of SolarCity stock caused a $0.01 gain in 2Q15 (with none left in 2015). We've also assumed +$0.03 for various regulatory matters and miscellaneous items as they've appeared in previous quarters.

On guidance, it is unclear at this time how management will continue to treat existing guidance given the latest delay for the GT&S ratecase, which will have rates retroactive to Jan 1, 2015. With 2015 guidance incorporating an assumption for nearly $0.60 of retroactive rates, the latest delay into Jan 2016 (followed by a separate decision on safety-related cost disallowances in May 2016) could create a binary outcome for 2015 depending on the timing. However, we are inclined to see management keep guidance where it is at $3.50-$3.70 (vs UBSe $3.61 and consensus $3.49) since the decision is retroactive even if too late to be incorporated into 2015 final results for the 4Q call.

Figure 135: PCG 2Q15E vs 2Q15A Walk

2Q15 Earnings Walk	EPS
2Q14 From EPS From Ops	**$0.69**
2014 GRC delayed cost recovery	
2014 expense recovery	$0.08
2014 ratebase growth	$0.06
2014 tax benefit - repairs method and forecast change	$0.05
2014 other	$0.02
Total 2014 GRC cost recovery	$0.21
2015 Growth in Ratebase Earnings	$0.05
GT&S timing (seasonality but -0.10 per q)	($0.10)
Timing of taxes and other benefits	($0.01)
Gain on Disposition of SolarCity Stock	($0.01)
Miscellaneous	$0.03
Dilution	($0.02)
2Q15E Non-GAAP	**$0.83**
2Q15 Consensus	***$0.72***
2015 Guidance	***$3.50-$3.70***
2015 UBSe	***$3.61***
2015 Consensus	***$3.49***

Source: UBS Estimates, Company filings, FactSet

For further context, please refer to our recent notes:

6/15/15 Moving Up North
4/30/15 Equitizing San Bruno
4/2/15 The Golden State Solar Net Metering Debate
4/1/15 The California Reset
3/23/15 Less Earnings Growth than Meets the Eye
2/11/15 Kicking Electric Vehicles Into High Gear

What's new with PCG?

- **Gas Transmission and Storage Case Schedule extended significantly.** On June 11, the California Public Utilities Commission amended the procedural schedule for PG&E's Gas Transmission & Storage ratecase, extending it to allow more time to consider which projects and programs are safety related and thus subject to the $850M cost disallowance awarded in the San Bruno decision in April. Instead of the previously anticipated August timeline, a decision for anticipated revenue requirements is now expected in Jan 2016 followed by a separate decision on safety-related cost disallowances in May 2016. A final deadline of December 2016 was also set, which we note would be 2 years past the originally anticipated wrap when the case was originally filed in 2014.

    - Hearings were completed on March 23, briefs were done on April 29 and reply briefs concluded on May 20. The question remains on how much of an ex-Parte communications penalty will be embedded in the decision (could be $100M's) and whether the company will appeal this aspect. The extraordinary ex-parte penalty was based on the number of months of delays caused (maxed at five through August 2015), but given the need for more time anyway, it would seem reasonable to us for these penalties to be dropped altogether at this point.

- **The utility plans to file its next General Ratecase (GRC) for 2017 on Sept 1, 2015.** Capex plans through 2016 are unchanged, although projected ratebase is lower for $700M future disallowed capital. We also note that the company has made no decision yet on either bringing the dividend up to alignment with peers or even on committing to a particular date or board meeting to do so. While the San Bruno decision did in fact remove management's stated obstacle to raising the dividend, we suspect that this latest delay for the GT&S case is likely to keep the issue sidelined while management awaits greater regulatory and political clarity.

While the San Bruno decision did in fact remove management's stated obstacle to raising the dividend, we suspect that this latest delay for the GT&S case is likely to keep the issue sidelined while management awaits greater regulatory and political clarity.

- **A bill was introduced in late June to make penalties for San Bruno non-tax-deductible (state level).** We expect the bill to wind its way through multiple committees from July 17-Aug 17, with the legislative session over on Sept 11. We note that the bill has an "urgency clause" which would put it into effect immediately instead of the usual Jan 1 timing.

- **Federal criminal charges for San Bruno remain pending.** Voir dire was conducted in March and there could be penalties of up to $1.1B eventually. Most recently, a ruling was granted for discovery requests as

parties attempt to determine the pipeline operator's understanding of the applicable regulations (e.g., to determine intent).

- **Two AG investigations for ex-Parte communications** remain ongoing. There have been no charges as yet to date.

- **Large electric vehicle proposal.** PCG's proposal is larger than SRE's and EIX's combined and could be a significant source of ratebase growth. The company has asked for expedited approval this year, but there's been no word from the CPUC yet on whether they agree to this.

- **A rate design PD was issued on April 21.** The proposal would reduce the rate tier system from 4 tiers to 2 by 2018 but would also postpone fixed charge implementation until 2018, applying less effective "minimum bills" in the interim. Time of Use (TOU) rates would also be implemented to customers paying fixed charges.

- **The company filed its Distribution Resource Plan on July 1,** as required by AB 327. The plan is mostly broad strokes, with details to be flushed out in follow-on workshops. We expect actual capital spending plans to be determined through that process and filed formally within future ratecases.

- **Legislation in California has been filed** to implement the Governor's 50% renewables goals. PCG has stated its preference for more of a holistic "clean energy" approach rather than a strict prescription for wind and solar only.

- **We see two 2016 issues as worthy of special attention:**

    - **Dividend growth** – what will management target beyond the near-term? Will there be a view to grow earnings in-line with EPS growth – or more to the extent growth has been lacking in recent years? We see management as ultimately aspiring towards a utility-average payout ratio with the questions being (1) when will increases come; and (2) whether management will opt for a large one-time increase to rebaseline or to increase the dividend growth rate to be greater than EPS growth to land in the target range over time? We note that the next Board of Directors meeting is scheduled for early May.

    - **Cost of Capital proceeding** – in light of lower interest rates and lower dividend yields in the sector, will the CPUC revise downwards its existing band? We see clear potentially risk here. This would also send a signal around a new era beyond Peevey's leadership.

Valuation: Maintain estimates and reduce PT $3 to $54 on lower peer P/E multiple

Figure 136: Updated PCG Mini-Model – Maximum Ratebase Earnings vs UBSe, 2014E-2018E

PG&E Mini-model (UBSe)	2014A	2015	2016	2017	2018	2019
Capex ($Bn)	4.9	5.5	5.4	5.6	5.6	5.6
Weighted Average Ratebase ($Bn)	28.2	31.0	33.1	34.9	38.0	40.3
FERC ratebase	*4.6*	*5.1*	*5.8*	*6.4*	*7.0*	*7.6*
CPUC elec ratebase	*18.1*	*18.7*	*19.8*	*20.6*	*22.8*	*32.4*
CPUC gas ratebase	*5.5*	*7.3*	*7.6*	*7.9*	*8.2*	*0.3*
Total Ratebase (including all disallowances)	28.2	31.0	33.1	34.9	38.0	40.3
Compare vs. PCG Guidance	28.2	31.0	33.1			
Ratebase Growth		*9.9%*	*6.7%*	*5.5%*	*8.8%*	*6.1%*
FERC Allowed ROE	10.90%	10.90%	10.90%	10.90%	10.90%	10.90%
CPUC Allowed ROE	10.40%	10.40%	10.40%	10.40%	10.40%	10.40%
Blended Allowed ROE	10.48%	10.48%	10.49%	10.49%	10.49%	10.49%
Authorized Equity Ratio	52%	52%	52%	52%	52%	52%
MAX ratebase earnings ($B)	1.5	1.7	1.8	1.9	2.1	2.2
Shares - Year End (Mn)	476	490	505	515	520	525
Shares - Average (Mn)	466	483	498	510	517	522
Equity Issued ($M)	844	750	750	500	250	250
MAX Utility Ratebase EPS	3.30	3.50	3.63	3.73	4.01	4.21
Growth		**6.1%**	**3.6%**	**3.0%**	**7.3%**	**5.1%**
Special Items 2014-2016						
Tax benefit – repairs method and forecast change	0.24	0.20	0.20	-	-	-
Expected GT&S under-recovery (~$50M)		(0.06)	(0.06)	(0.06)	(0.05)	(0.05)
Expected offseting savings and other benefits		0.06	0.06	0.06	0.05	0.05
2014 GRC expense recovery (2013 & 1H14)	0.30					
Timing of taxes and other expenses	-					
Regulatory matters	0.02					
Miscellaneous	(0.01)					
Sale of Solar City stock	0.06	0.03				
Parent EPS	($0.03)	($0.03)	($0.03)	($0.03)	($0.03)	($0.03)
MAX PCG EPS	3.88	3.69	3.79	3.70	3.97	4.18
EPS in model	**$3.50**	**$3.61**	**$3.75**	**$3.68**	**$3.91**	**$4.13**
Growth		*3%*	*4%*	*-2%*	*6%*	*6%*
ROE in model	11.11%	11.04%	11.00%	10.43%	10.34%	10.37%
ROE in model before special items 2014-2016	9.29%	10.23%	10.36%	10.43%	10.34%	10.37%
Prior Estimates	$3.50	$3.61	$3.75	$3.68	$3.91	$4.13
Consensus		***$3.45***	***$3.82***	***$3.74***	***$3.93***	
Guidance		***3.50-3.70***				

Source: Company Filings, FactSet, and UBS Estimates

Remaining on the sidelines

Our valuation remains based on 2017E, with a $54 target. Our estimates are based on a 1Q updated capex and ratebase forecast as well as a lower equity requirement due to better than expected cash flows from balancing account activity and timing of spending. We remain cautious on the outlook for PCG in light of the state and federal proceedings/investigations but believe that the negative overhangs essentially counterbalance the premium enjoyed by other California utilities for the abundance of capital opportunities and above-average ROEs. An important distinction between PCG and peers is that the PCG's equity dampens the translation from above-average ratebase growth to EPS growth. We struggle to see PCG sustainably trading at any meaningful premium over the horizon, particularly given the challenging regulatory climate.

In contrast we apply 1x-turn premiums to Edison International (SCE) and Sempra (SDG&E and SoCal Gas); in a scenario where PCG did not face AG prosecution/ex-parte risks **and** did not have to issue extra equity, the utility could trade at a premium like peers. The electric vehicle filing that was larger than the initial requests of EIX and SRE combined was a tipping factor in the removal of the discount from our valuation along with the storage filing late last year.

We continue to see a marginally negative risk/reward bias. For those with a longer-term view, we see potential to pick up shares at a discount, or perhaps ~in-line with peers assuming further dilution from subsequent settlements, etc. Any negative datapoint or legal finding on the numerous open dockets/investigations could drive investors to value PG&E at a further discount in the near-term.

Despite the premium growth ratebase profile, the question remains whether the ongoing halo of regulatory risk will persist into 2016/17? We're biased to see PCG trade at a discount to EIX, and see greater value in shares of EIX, especially as it currently trades as an even lower discount due to excessive (in our view) concerns over some calls for a reopening of the SONGS settlement (we think unlikely).

Figure 137: Updated PG&E Valuation – trades at slight discount to peers still

PG&E Corp Valuation (UBSe)	Low Case	Base Case	Upside Case
Ongoing EPS - 2017E	$3.68	$3.68	$3.68
Group P/E	13.7x	14.7x	15.7x
(Discount)/Premium	(5.0%)	0.0%	5.0%
Price Target	**$48.00**	**$54.00**	**$61.00**
Upside/(Downside)	**-10%**	**1%**	**14%**

Source: Company Filings, FactSet, and UBS Estimates

Pinnacle West (Buy; PT $65)

Expect another miss on mild weather but nothing to be concerned about.

We expect a miss for the 2Q at **$1.19** vs consensus $1.25, largely due to -$0.01 of mild weather in 2Q15 (vs a favorable $0.04 in 1Q14). Higher D&A is offset by higher rates for Four Corners vs deferrals a year ago (as well as the extension of the lease on Palo Verde). The LFCR mechanism helps a penny. Interest is down a few pennies on refinancings, including $250M issued in early January and additional debt in May. O&M should be flattish for the year but was -$0.02 higher in 1Q, so we assume the same for this quarter. Transmission is likely flat through YoY comps of the Transmission Cost Adjustment (TCA). AZ Sun should be up a few pennies on Gila Bend. We don't expect an update to 2015 guidance of $3.75-$3.95 vs UBSe $3.86 and consensus $3.85.

The Admin Law Judge (ALJ) is set to make a recommendation this summer regarding the recently filed request for a $20/month grid access charge within docket 13-0248 (vs $4.90 currently). We expect the ALJ to be supportive of the concept in general while pushing the increase into next year's ratecase filing,

Figure 138: PNW 2Q15E vs 2Q14A Walk

2Q15 Earnings Walk	EPS
Reported 2Q14 Adj. EPS	**$1.19**
Normal Weather	($0.04)
Normalized 2Q14 EPS	**$1.15**
Weather vs. Norm	($0.01)
Weather norm sales growth 0.5	$0.00
Wholesale contracts	($0.02)
LFCR	$0.01
D&A	($0.06)
Interest Expense	$0.03
O&M	($0.02)
Other taxes	$0.01
Transmission TCA	$0.00
4 Corners Rate Change	$0.08
AZ Sun	$0.03
Other, net	($0.01)
Dilution	$0.00
UBSe 2Q15 Adj. EPS	**$1.19**
Consensus	$1.25
2015 Guidance	**3.75-3.95**
UBSe 2015	**$3.86**
Consensus 2015	**$3.85**

Source: UBS Estimates, Company Filings

For further context, please refer to our recent notes:

6/18 Sunrise after the Slide
6/9/15 Preparing for the California Rate Design Shift
6/2/15 Calming Concerns on California
5/4/15 Maintaining a Low Profile
4/2/15 The Golden State Solar Net Metering Debate
2/23/15 Above the Fray for 2015
1/28/15 Nice Sunset in Arizona - Downgrade to Neutral
1/22/15 4Q Playbook: Losing a Bit More of Its Veneer
12/19/15 The 'SMID Bid': The Context for Regulated M&A
11/3/14 Diamondback in the Rough

What's new at PNW?

While residential solar applications remain strong this year, we expect PNW to achieve at least 9.5% ROE until next rate increase.

- **Early preparation work for the mid-2016 ratecase filing has begun.** In the meantime, briefs and oral argument have been heard in the grid access charge docket (13-0248) that was filed on April 2. An ALJ recommendation is expected this summer; we expect this to focus more on whether the discussion should continue outside of a ratecase context rather than the substance of the utility's request for a significantly higher charge (see details below).

- **We do not expect a vote this year for the generic rate design docket** 14-0329 that started in September to consider procedures for ratecases or other processes. We expect these issues to be discussed and dealt with in the context of the next ratecase, which will be filed June 1, 2016 for rates effective in July 2017. Nevertheless, the Admin Law Judge (ALJ) is set to make a recommendation this summer regarding the recently filed request for a $20/month grid access charge within docket 13-0248 (vs $4.90 currently). We expect the ALJ to be supportive of the concept in general while pushing the increase into next year's ratecase filing, along with the currently stalled rate design discussion under docket 14-0415. While residential solar applications remain strong this year, we expect PNW to achieve at least 9.5% ROE until next rate increase.

- **APS declared its intention to join the western interconnect Energy Imbalance Market** in mid-May. Utility APS announced plans to join the western interconnect Energy Imbalance Market (EIM) in Oct 2016, with systems ready by next summer. Note that the takeover of NV Energy by Berkshire in 2013 was preceded by NV Energy joining the EIM.

- **We do not expect any change to guidance** for the year of $3.75-$3.95 vs UBSe $3.86 and consensus $3.85. Weather norm sales growth forecast remains 0.5%-1.5% for 2015-2017, which excludes drags of -1% from EE and conservation and another -0.5% from distributed gen.

- **In May, APS' self-build expansion option at Ocotillo (3 GE 102-MW turbines) was chosen** in the RFP for 300 MW of dispatchable peaking capacity by the summer of 2018 or 2019. At the same time, the cost estimate for the project was reduced to $500M from a previous estimate of $600M-$700M. The in-service date was pushed out a year too to 2019.

- **With a 54% equity ratio at APS, no secondary equity is expected** to be needed until 2017 at the earliest (we assume $250M in our 2017 modelling).

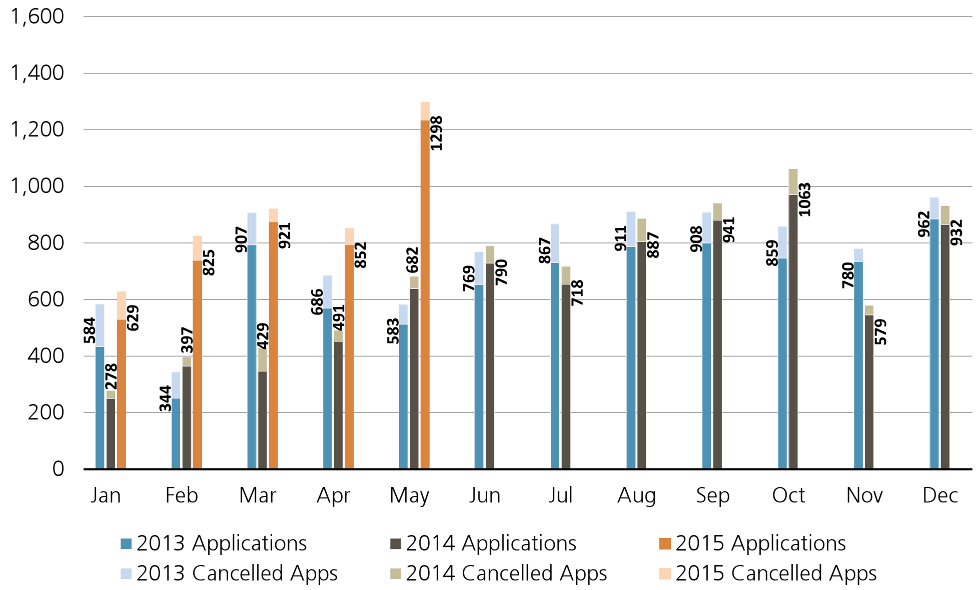
- **We expect another RFP in 2016 for end-of-decade generation needs**, to include solutions for the expiration of the Gila River and Arlington contracts from 2017-2019. Ratebasing the plants might be one possible pathway. The company also has two 10-year heat rate option contracts expiring at the end of 2015 (500 MW and 150 MW) that have been used for hedging but as generic instruments, these have never matched load very efficiently.

- **Expect the winner to be announced for the Delaney Colorado River Transmission Line** under CAISO's competitive solicitation by Aug 31 (possibly as early as July). The line is expected to be in-service by 2020. With its existing JV with Mid-American and the current partnership with Southern California Electric (SCE), and given historical sensitivities around 'taking from AZ', we suspect APS is well positioned despite four other competitors. The partnership with EIX's utility SCE provides a powerful competitor for a project we expect to

bitterly contested. If chosen, the project would likely add to PNW's capital budget from 2017+.

- **Preliminary residential solar applications through May 2015 are up over 100%** year over year as monthly totals seem to have been gravitating toward a steady state of ~800 since June 2014 (although May appears to have set a new record). See table below for a month by month comparison. As of March 2015, over 237 MW of residential grid-tied solar photovoltaic (PV) systems have been installed in APS's service territory, with an additional 23 MW reserved.

Figure 139: Residential PV Applications in APS Territory, 2013-2015



Source: Company filings, www.arizonagoessolar.org

Valuation: Raise PT $2 to $65 on higher recent peer P/E multiple

Our valuation is based on a 5% premium to the average peer utility 2017E P/E.

Figure 140: PNW Valuation

Pinnacle West Valuation: P/E Derived on 2017 EPS					
Downside Case		***Base Case***		***Upside Case***	
Valuation		**Price Target**		**Valuation**	
2017 EPS	$4.24	2017 EPS	$4.24	2017 EPS	$4.24
P/E Multiple	14.7x	P/E Multiple	14.7x	P/E Multiple	14.7x
Premium/(Disc.)	-10%	'Premium	5%	'Premium	10%
Value	**$56.00**	**Value**	**$65.00**	**Value**	**$68.00**

Source: Company Filings, FactSet, and UBS Estimates

We continue to assume $250M of equity issued in 2017 to maintain an authorized 54.1% equity ratio as the company funds the construction of Ocotillo, among other capital plans. For 2017E, we remain ~1% below consensus, the delta would drive ~$0.60/sh of additional value in our methodology.

Figure 141: PNW 2015E+ Estimates Remain Unchanged

	2013A	2014A	2015E	2016E	2017E	2018E
UBS estimates	$3.66	$3.58	$3.86	$4.01	$4.24	$4.51
Prior estimates	$3.66	$3.58	$3.86	$4.01	$4.24	$4.51
Guidance			$3.75-$3.95			
Consensus	$3.66	$3.58	$3.85	$4.02	$4.21	$4.37

Source: Company Filings, FactSet, and UBS Estimates

PPL Corp (Neutral; $31)

Quarter appears fine although if UK tax benefits do not materialize it could be a miss. We look to see if mgmt decided to pay-up to lock-in F/X hedges to improve the 2017E earnings profile at the UK. Synergy refresh could also be a catalyst but mgmt has shied away from quantitative updates.

Flat/in-line quarter if tax benefits are able to compensate for first quarter of RIIO rate step-down in the UK.

We forecast PPL reporting adjusted 2Q15 EPS of **$0.48**, a slight beat versus Consensus ($0.47) and essentially flat versus the PPL Supply-adjusted 2Q14. The UK was up +$0.09 YoY in 1Q due to favorable weather and last quarter of recording revenues under the DCPR5 pricing regime. The transition to RIIO is expected to have a negative impact on revenues but is offset by lower taxes for the most part in 2015 and is fully contemplated in management's guidance. We also expect similar performance for the Kentucky (+$0.00) and Pennsylvania (+$0.01) utilities as they did in the first quarter with a slight improvement at the Parent. Kentucky should see more growth in 2H15 with its new rates effective July 1st following its recently approved settlement. PPL anticipates $0.11 of improvement for the Parent in 2015 although we see this shaped towards 2H15 (-$0.08 loss in 4Q14).

Figure 142: PPL 2Q15 Earnings Walk

PPL Corp. Earnings Walk	EPS
2Q14A EPS	**$0.53**
Supply Ongoing 2Q14A - *Removing from Ongoing*	(0.06)
2Q14E EPS Adjusted - Regulated Only	**$0.47**
U.K. Regulated (PPL UK)	**$0.00**
Utility revenue: New RIIO-ED1 Rates begin in 2Q15	(0.05)
O&M	-
Depreciation	-
Financing	0.01
Income Taxes & Other	0.04
Kentucky Regulated (LG&E and KU)	**$0.00**
Gross margins: New Rates Effective July 2015	0.01
O&M	(0.01)
Income Taxes & Other	-
Pennsylvania Regulated (PPL EU)	**$0.01**
Gross margins: Rate case pending for FY16	0.01
O&M	(0.01)
Income Taxes & Other	-
Parent & Other	**$0.00**
Corporate Restructuring, Taxes, & Other	0.01
Dilution	0.00
2Q15E Ongoing EPS	**$0.48**
Consensus	***$0.47***
2015 Guidance	$2.05-$2.25
2015 UBSe (ex. PPL Supply and Parent Adj)	$2.20
2015 Consensus	$2.19

Source: Company Filings, FactSet, and UBS Estimates

For additional context, please refer links to relevant recent reports below:

7/1/15 Peering Across the Pond: Ofgem's RIIO
6/8/15 Utilities Stand Alone
5/11/15 Adding a Jewel to the Crown
2/6/15 Wait and See With GBP

What's new with PPL?

- **PA case still in the starting blocks with developments later this summer/fall:** Following the Talen spin and settlement of the Kentucky rate cases, the next big development for regulated-only PPL pertains to the Pennsylvania rate case filed in March. The case carries a $167Mn rate increase premised on a 10.95% ROE and 51.7% equity ratio. **Aside from early intervenor testimony, we see the hearings later this summer and briefs in the Fall.** Exelon (PECO) similarly filed for a $190Mn base rate increase with a 10.95% ROE and 53.4% equity ratio. Decisions in both cases are expected by year-end with new rates effective for the start of 2016. There are few datapoints on ROE available as the eight rate cases completed since 2013 have been settled with ROE requests between 10.90-11.25%. PPL, Exelon, and NiSource (Columbia Gas) have all requested rate increases with identical 10.95% ROEs and similar equity ratios. For context in 2014 the average authorized ROE was 9.91% according to SNL RRA.

We do see some ROE risk here with the $167Mn 10.95% ROE request pending.

Figure 143: Pending Pennsylvania Rate Cases

State	Company	Ticker	Case ID	Service	Case Type	Filing	Rate Inc. ($Mn)	Rate Inc. (%)	ROE (%)	Equity (%)	Ratebase	Action By
All PA Pending Cases												
PA	Columbia Gas	NI	D-R-2015-2468056	Gas	Distribution	03/15	46.2	8.63	11	52.21	1,325	12/15
PA	PECO Energy Co.	EXC	D-R-2015-2468981	Electric	Distribution	03/15	190.1	4.4	11	NA	4,104	12/15
PA	PPL Electric Utilities	PPL	D-R-2015-2469275	Electric	Distribution	03/15	167.5	NA	11	51.66	3,156	12/15

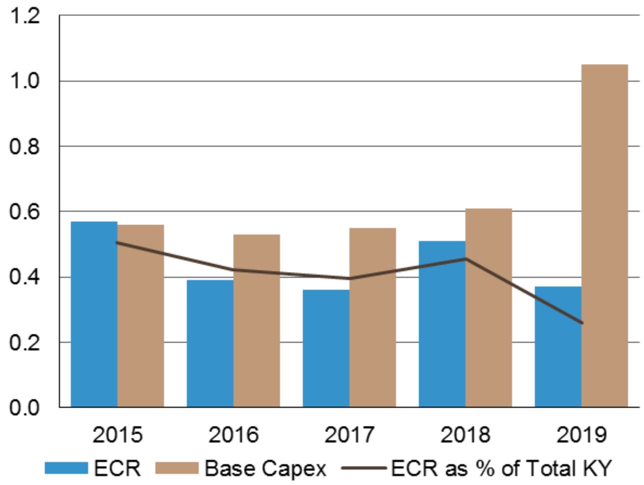
Source: SNL RRA

- **Synergy updates could come now, or later:** In management's first earnings call since the Talen spin-off earlier this summer, we anticipate an update on how cost savings initiatives are trending. PPL has remained conservative in its guidance and may not yet be in a position to provide an update, instead opting to wait until it releases 2015 guidance to update its disclosures.

- **New Kentucky rates approved:** On June 30th the Kentucky PSC approved PPL's rate case settlement for LG&E and KU for $132Mn rate increase versus a $198Mn request. The settlement was silent on base ROE but ROE but PPL originally requested a 10.5% ROE. The settlement does include a 10% ROE for the Environmental Cost Recovery mechanism (ECR) and gas line trackers, an important detail as management sees the "bulk" of the capex flowing through the mechanisms. Over the next four years the ECR capex averages about $500Mn per year, or about 45% before declining to 25% of total Kentucky capex due to a combination of base increasing and environmental declining.

PSC approves Kentucky settlement. New rates effective July 1st will help stimulate growth. Look for bulk of spending to fall under Environmental rider in next few years given the 10% ROE.

Figure 144: Kentucky Estimated Capital Spending ($Bn except ECR %)



Source: Company Filings

- **Can load growth buck the trend?:** 1Q15 weather normalized sales growth was negative for both KY (-50bp) and PA (-120bp) and declined slightly for the full-year. The longer-term has been lackluster as well, particularly in Kentucky and we look for signs of improvement with 2Q15 results.

- **Still early for Compass:** In recent months PPL has been silent on discussion of the $4-6Bn Compass transmission project which was announced last Summer and the last update we received was in November 2014 when management commented that its conversations with stakeholders were progressing. To date management has commented that there have been no setbacks but the discussions with state regulators and politicians are still in the early phases.

Mgmt is still in the education/outreach phase of Compass.

Assuming that project receives the greenlight it would not start construction until 2017 and would not have a material impact on the 2014-2017 growth profile. The near-term question remains whether PPL can achieve positive milestones to prove the viability of the project to investors who largely appear to avoid prescribing value to the project. If successful here, this could be the centerpiece of post-Talen earnings growth.

- **Virginia rate case filed – not a driver:** PPL filed for a $7Mn rate increase in Virginia with a 10.5% ROE and 54.1% equity ratio for its $220Mn rate base. For context, as mentioned previously PPL requested $198Mn in Kentucky (awarded $132Mn) and $168Mn in Pennsylvania.

- **Life after Talen – S&P upgrades PPL:** After divesting the merchant exposure of PPL Supply and transitioning to a fully-regulated utility S&P upgraded PPL Corp and its subsidiary credit ratings to 'A-' from 'BBB'. With a more favorable business profile in the eyes of regulators, we look for commentary on if and how management sees itself deploying its balance sheet in the future

- **No MATS impact here either:** According to SNL, PPL has 4.1GW of operating capacity that has received MATS extensions, the largest of which is the 1.5GW Mill Creek plant in Kentucky. Management commented that the

recent Supreme Court ruling has not changed any of its compliance plans given the capital already dedicated to date.

EPS estimates remain unchanged

To arrive at consensus' 2018 EPS estimate we would need to make optimistic assumptions such as that the UK utilities can grow materially despite the bonus revenue step-down and that the entirety of the legacy Supply drag goes away, including the $0.05 of interest expense for the $880Mn of debt.

We do not see the 4-6% EPS growth rate from 2014-2017 as achievable without a recovery in the foreign exchange rate.

Figure 145: PPL Earnings Estimates

PPL Standalone EPS (UBSe)	2014A	2015E	2016E	2017E	2018E	14A-'17E CAGR
UK Utilities	1.37	1.38	1.35	1.29	1.28	-2%
PA Electric Utility	0.40	0.43	0.48	0.50	0.52	8%
Kentucky Utilities	0.47	0.48	0.50	0.53	0.55	4%
Retained Supply Corp. & Other	(0.21)	(0.10)	(0.07)	(0.06)	(0.06)	
Total	**2.03**	**2.20**	**2.25**	**2.25**	**2.29**	**4%**
Prior UBSe	*2.03*	*2.20*	*2.25*	*2.25*	*2.29*	
Consensus (7/9/15)	*2.03*	*2.19*	*2.29*	*2.32*	*2.46*	*5%*
Guidance		*$2.05-$2.25*				

Source: Company Filings, FactSet, and UBS Estimates

Valuation: Maintain $31 Price Target

Our valuation and 2017E methodology is unchanged. We apply a 1x-discount to the international utilities and a 0.5x-discount to Kentucky operations due to growth constraints in both jurisdictions. The Pennsylvania utilities are ascribed a 1x-premium due to the favorable regulatory construction and above-average EPS growth.

Figure 146: Updated PPL Valuation

PPL Sum-of-the-Parts (UBSe)	2017E	P/E Multiples					Enterprise Value		
	P/E	Low	Peer	Prem/ Disc.	Base	High	Low	Base	High
International (UK) Utilities	$1.29	*12.3x*	14.3x	-1.0x	*13.3x*	*15.3x*	$10,807	$11,685	$13,442
Domestic Regulated Utilities									
PPL Electric Utilities (PA T&D)	$0.50	*14.3x*	14.3x	1.0x	*15.3x*	*16.3x*	$4,897	$5,240	$5,582
PPL Kentucky (KU/LG&E)	$0.53	*12.8x*	14.3x	-0.5x	*13.8x*	*14.8x*	$4,605	$4,965	$5,325
Parent Interest Expense Drag	-$0.06	*13.3x*	14.3x	0.0x	*14.3x*	*15.3x*	($547)	($588)	($629)
PPL Equity Value							$19,762	$21,302	$23,720
Shares Outstanding (2017E Mn)							683	683	683
Total PPL Equity Value Per Share							**$29.00**	**$31.00**	**$35.00**
Implied P/E							**12.8x**	**13.8x**	**15.4x**
Premium/(Discount) to Group							**-1.5x**	**-0.5x**	**1.1x**

Source: Company Filings, FactSet, and UBS Estimates

PSE&G (Neutral, $41 PT)

With a quiet quarter forecasted, PJM datapoints will dominate discussions early in the summer as attention will transition towards the NJ BPU gas modernization proceeding.

We forecast PSE&G reporting adjusted 2Q15 EPS of **$0.52**, slightly below Consensus ($0.52) but higher YoY as Power is able to overcome capacity market headwinds. The utilities are expected to record another solid quarter of growth due to continued transmission investment. Growth at Power is more complex given the large capacity revenue step-down (-$0.08) but that is partially offset by improved energy revenue (management guides to energy and capacity largely offsetting for the full year). In 2Q14 PEG had outages at Salem and Linden which reduced the quarter's performance by ~$0.06-$0.07/sh due to direct/indirect costs. The magnitude of the uplift is reduced slightly due to a planned Hope Creek outage from April 13-May 11.

We project a slight miss versus Consensus but

Figure 147: PSE&G 2Q15 Earnings Walk

2Q14A Adj. EPS	$0.49	*Notes*
PSE&G YoY	0.02	
Transmission Investments	0.03	*Increase in Ratebase of ~$1 Bn*
Weather/Volume Impact	-	*Unfavorable weather in 2Q14 and 2Q15*
Renewables, CIP, & Other	0.01	
O&M Growth	(0.00)	*Slight growth with in O&M and pension but offsets present*
D&A	(0.01)	*Increase mostly offset by the transmission growth*
Taxes and Other	0.00	
Power YoY	0.01	
Capacity Payments	(0.08)	*1.3GW less for 2015/2016 vs 2014/2015*
Hedges & Output Volume	0.04	*Increase in expected annual generation (~2TWh) and $4/Mwh higher prices*
Weather/Volume Impact	-	
O&M Growth	(0.01)	*2% Annualized Growth*
Outages	0.06	*Reversal of 2Q14 extended outages at Salem and Linden*
D&A	(0.00)	*Ordinary uptick in depreciation*
Interest Expense	-	*Slight benefit from Power Refinancing*
Pension	(0.01)	*Both Utility and Power headwind*
LIPA Fuel Mgmt Contract	0.00	*Services arrangement - slight uplift YoY*
Energy Holding YoY	-	*No change in LIPA compensation*
Corp. YoY		
Corp/Other/Interest	-	
2Q15E UBS Adj. EPS	$0.52	
2Q15 Consensus	*$0.55*	
2015 UBSe	*$2.84*	
2015 Guidance	*$2.75-$2.95*	
2015 Consensus	*$2.94*	

Source: Company Filings, FactSet, and UBS Estimates

For additional context, please refer links to relevant recent reports below:

6/18/15 The Right Keys to Unlocking Value
5/6/15 Voted off Artificial Island
3/13/15 Doubling Down on New Jersey
2/18/15 Deconstructing the Risks in NJ's BGS Auction

What's new with PSE&G?

- **Stage set for GSMP this summer:** Public hearings have begun in the $1.6Bn Gas System Modernization Program (GSMP) proposal and a Commissioner has been appointed although there has not been material developments as of yet. Commissioner Joseph Fiodaliso will preside over the GSMP docket, it is worth noting that Fiodaliso was the Commissioner on the Energy Strong proposal as well. Management believes they have de-risked the proposal by following the lessons learned with the Energy Strong capex plan but this is still a large request that will be closely followed to determine the earnings trajectory throughout the decade. PEG has commented that early feedback has been positive given the backdrop of declining gas prices dampening the bill impact and the jobs benefit.

Key question is how many years of gas spending the BPU could approve.

Settlement talks are scheduled for July but significant progress is unlikely so early in the process (October timeframe is higher probability as case progresses throughout the Summer and Fall). Assuming that the GSMP is approved, PSE&G would have a thirty-year replacement cycle, similar to regional peers ConEd, BG&E, and PECO, enhancing/extending the already above-average growth story.

- **Could there be another twist in the Artificial Island saga:** The FERC is set to meet on July 29th to issue a final decision on the Artificial Island transmission project in Southern New Jersey (the location for both the Salem and Hope Creek nuclear facilities). Previously on April 28, PJM's Transmission Expansion Advisory Committee (TEAC) recommended that LS Power Group construct the transmission project, reversing its June 2014 decision that had chosen PEG's solution. The LS Power proposal include more extensive undergrounding, potentially reducing environmental compliance issues, which may have been a significant factor. Despite the loss, PSE&G still expects to invest $100M-$130M as a result of required expansions and upgrades to existing facilities for the LS Power project. We do not anticipate a change from the TEAC recommendation but the Artificial Island has surprised investors in the past.

There is still a chance that PJM makes a 180-degree change on Artificial Island although unlikely.

Further details are available in our note, **'The Final Four on the Artificial Island'**.

Figure 148: "Final Four" PJM Artificial Island Proposals

Revised Artificial Island Proposals				
Owner	*Project*	*Cost Est./Cap ($Mn)*	*Cost Cap?*	*In-Service Estimate*
Dominion	P2013 1-1A	$163.9-$174.1	None	January-November 2018
Dominion	P2013-1-1C	$322-$372	None	2021-2023
Transource	P2013_1-2B	$203-$255.3	Yes	~2018/19 (~48 months)
PSE&G	P2013-1-7K	$221	Yes	~2018/19 (52 months)
LS Power	P2013-1-5A	$146	Yes	November 2018 (42 months)

Source: PJM Interconnect and UBS Estimates

- **Flipping the switch on PEG Power – Premium Keys development worth ~$1.50/sh:** On June 17 PEG Power announced the purchase of the 755MW Keys Energy Center development project from private equity firm Ares EIF. The $825-875Mn Maryland plant benefits from PEPCO premium power pricing (~9% premium to PJM-West) and favorable gas pricing (Dominion-South plus ~$0.05/mmbtu sourced off D's Cove Pt pipeline lateral). We initially estimate very strong equity (22%) and unlevered IRRs (12%); however, we would expect to see the economics erode in the future as capacity constraints are alleviated, and gas takeaway improved. We est. $140Mn EBITDA and $0.10/sh EPS, implying ~$1.50/sh equity value.

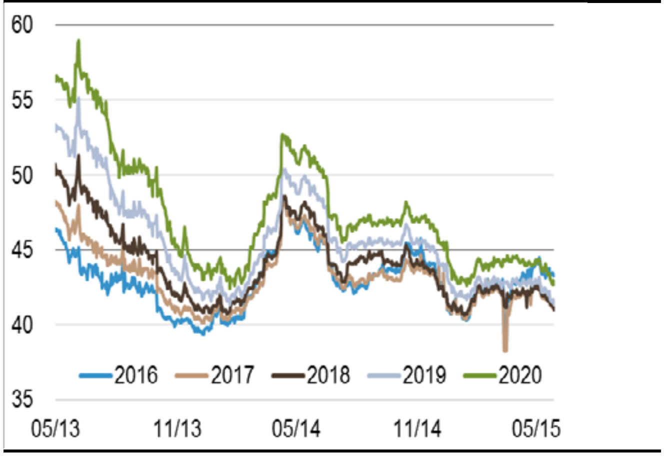
Below we present our estimates for the 755MW Keys Energy Center which benefits from the combination of high power (PEPCO) and low gas (Dom-South).

Figure 149: Keys Energy Center Mini-Model

Keys Energy Center Mini Model*	2015E	2016E	2017E	2018E	2019E
Capacity (MW)	755	755	755	755	755
Capacity Factor, UBSe	75.0%	75.0%	75.0%	75.0%	75.0%
PJM-East [PEPCO] ATC ($/MWh)	$43.5	$43.3	$41.1	$41.1	$41.4
Heat Rate, UBSe	6,800	6,800	6,800	6,800	6,800
Fuel & Transport [Dominion-South] ($/MWh)	($14)	($14)	($17)	($17)	($17)
Energy Margin ($MWh)	$29	$29	$24	$24	$24
Generation (TWh)	5.0	5.0	5.0	5.0	5.0
Energy Margin ($Mn)	$143.9	$142.9	$121.3	$117.0	$118.6
PJM MAAC Capacity Payment ($/MW-day)	$155	$139	$120	$143	$160
Capacity Revenue ($Mn)	$40	$36	$31	$38	$42
O&M ($/kW-yr), UBSe	20	20	20	20	20
O&M ($ Mn)	15	15	15	15	15
EBITDA	**169.3**	**164.3**	**137.5**	**139.4**	**145.4**
EV / EBITDA	5.0x	5.2x	6.2x	6.1x	5.8x
Debt / EBITDA	3.0x	3.1x	3.7x	3.7x	3.5x
Taxes	39	37	27	28	30
Interest Expense	31	31	31	31	31
Maintenance Capex	8	8	8	8	8
Equity Free Cash Flow	**92**	**89**	**72**	**73**	**77**
Net Income	72	68	51	52	56
EPS	**$0.14**	**$0.13**	**$0.10**	**$0.10**	**$0.11**
ROE	21.1%	20.1%	15.0%	15.4%	16.5%
Equity IRR		**23% Unlevered IRR**			**12%**

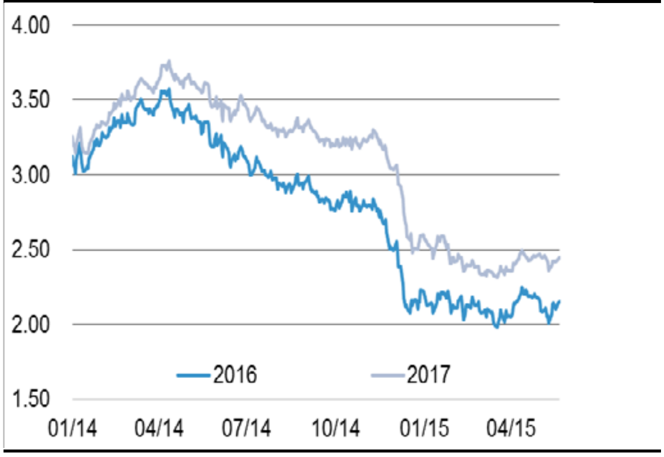
Source: Company Filings, Platts, Bloomberg, and UBS Estimates * 2018 COD; Full-Year 2015-2018 Estimates are Illustrative

Figure 150: PEPCO Forward Power Pricing ($/MWh)



Source: Platts/Bloomberg

Figure 151: Dominion-South ($/mmbtu)



Source: Platts

- **What does this signal about business mix? CCGT exposure now surpasses nuclear**: Although management has been vocal in recent months about deploying the balance sheet, prior to the recent deal we perceived skepticism from investors after the Bridgeport Harbor CCGT development did not clear in ISO-NE. This acquisition shows a renewed commitment to the Power side of the business and could hint that further development is coming (management highlighted five conventional power opportunities at its Analyst Day), a key positive for shares. We caution that the economics of this well-located Keys plant are particularly attractive and does not necessarily signal that PEG is relaxing its historically conservative investment criterion.

- **What about the legacy HEDD Units?** *Could keep more MWs around in PJM to comply with SCR requirements depending on clearing price of CP.* The company could be poised to announce positive updates around the size of its portfolio with 2Q-- albeit adding limited NPV seeing the added cost of installing SCRs on the gas units to comply with the Summer NO_x rules, otherwise known as the NJ HEDD rule. While the upcoming CP auction print could incentivize new development, we ultimately believe that management will opt to **not** go ahead with the large power capex projects such as Edison/Essex environmental retrofit. It is clear that the strategy is to "tuck-in" incremental MWs when there is a clear cost advantage

Figure 152: Incremental Power Investment Opportunities – Not in base plan

Site	Project	Benefits
Bridgeport Harbor	CCGT Development	475MW Capacity (ISO-NE)
Hope Creek	Capacity Uprate	20MW Capacity (PJM)
Edison/Essex	SCR Retrofit	Maintain 800MW
Bergen	Bergen 1 Uprate	50MW Capacity (PJM)
Sewaren	CCGT Development	450-625MW Capacity (PJM)
Various	Solar Investments	100s MW Capacity

Source: Company Filings

- **No update on PJM cost-based bidding:** The PJM cost-based bidding questions have lingered for the past year but the market has not received any update – it appears that this could take a while still to achieve resolution

- **Penn East FERC filing another Summer item:** Town hall and other local hearings have been conducted regarding Penn East and we still anticipate a FERC filing this Summer (~3Q).

Estimates fractionally lower in 2016/2017

The reduction in our forward estimates is due to commodities from our quarterly mark-to-market.

Figure 153: Updated PEG EPS Estimates

PEG EPS Estimates	2012A	2013A	2014A	2015E	2016E	2017E
PSEG Power	1.27	1.40	1.26	1.26	1.05	0.87
PSE&G	1.04	1.21	1.43	1.51	1.69	1.84
PSEG Enterprise & Other	0.13	(0.03)	0.07	0.07	0.07	0.10
Total	***2.44***	***2.58***	***2.76***	***2.84***	***2.81***	***2.81***
Prior	2.44	2.58	2.76	2.84	2.82	2.83
Consensus				**2.94**	**2.93**	**2.99**
% Regulated	43%	47%	52%	53%	60%	65%
Regulated EPS CAGR ('13--'16 & '14-17')					12%	9%
Guidance				**$2.75-$2.95**		

Source: Company Filings, FactSet, and UBS Estimates

Valuation: Reduce Price Target by $2

We continue to use a 2017E sum-of-the-parts methodology and we have lowered our Price Target by $2 split approximately evenly between the contracting peer multiple and a reduction in power prices.

Figure 154: PSE&G Valuation

Sum of the Parts Analysis - Hedged Analysis - UBSe							
All figures in USD millions except per share	2017E Adj. EBITDA	EV/EBITDA & P/E Multiple			Enterprise Value		
		Low	Base	High	Low	Base	High
PSEG Power	1,174	8.0x	9.0x	10.0x	9,389	10,563	11,737
Capacity Price Normalization @ $120/MW-day	(156)	8.0x	9.0x	10.0x	(1,244)	(1,400)	(1,555)
PSEG Enterprise /PSEG LI (LIPA)	57	5.0x	6.0x	7.0x	284	341	398
Corp. & Other	-	4.0x	5.0x	6.0x	-	-	-
Total / Implied	*1,075*	*7.8x*	*8.8x*	*9.8x*	*8,429*	*9,504*	*10,579*
Subtract: Net Debt						(3,093)	
Add: Three years of PS Premium Capacity Pricing (NPV) over $120/MW-day						471	
NPV of Power and Non-Reg Equity					5,336	6,882	7,486
Number of Shares Outstanding (2017E)					508	508	508
Power & Holdings Equity Value per Share using Hedged EBITDA					$10.51	$13.56	$14.75
Maintenance Capex						($190)	
FCF (EBITA - Maintenance Capex)						$725	
Implied FCF Yield on Power Equity						*10.53%*	
	2017 Net Income	P/E Multiple					
PSE&G Net Income	932	14.2x	15.2x	16.2x	13,237	14,169	15,102
	Peer Multiple =		*14.7x*				
	Premium/Discount =		*0.5x*				
Number of Shares Outstanding (2017E)					508	508	508
PSE&G Equity Value Per Share					$26.08	$27.92	$29.76
Total Equity Value per Share					$37.00	$41.00	$45.00

Source: Company Filings, FactSet, and UBS Estimates

SCANA Corp. (Neutral, $56 PT)

Expect an in-line quarter with discussion of the recently announced VC Summer schedule and cost revision settlement the focus of the call.

We expect an in-line quarter at $0.64 vs consensus $0.62. Mild weather reduces earnings a nickel and we expect to see another -$0.04 of 2Q dilution from the sale of CGT and SCI (expected to be overall dilutive -$0.04 for the full year 2015 followed by +$0.04 accretion in 2016). This is offset by +$0.08 of higher BLRA revenues for the VC Summer nuclear construction project. Depreciation, interest, and dilution reduce YoY comps by another -$0.03. We do not expect any significant change to earnings guidance at this point in the year.

Figure 155: SCG 2Q15E vs 2Q14A Walk

2Q15E Earnings Walk	EPS
2Q14A EPS	**$0.68**
Weather 2Q15 vs 2Q14	($0.05)
Other Electric Margin & Income	
Sales Growth (co guid -0.6% decline in 2015)	$0.00
Base Load Review Act (BLRA)	$0.08
Gas Margin	
E&G Gas Rate Stabilization Case	($0.00)
O&M relatively flat in 2015	$0.00
CGT earned through Jan (not seasonal)	($0.03)
SCI sold in Feb	($0.01)
Hybrid debt paydown from CGT proceeds	$0.01
Issued $500M debt in May 5.1%	($0.01)
Depreciation	($0.02)
Dilution	($0.01)
2Q15 EPS UBSe	**$0.64**
Consensus	*$0.62*
FY15 UBSe	*$3.69*
TTM UBSe	*$3.77*
2015 Guidance	***$3.60-$3.80***

Source: UBS Estimates, Company filings, FactSet

For further context, please refer to our recent notes:

6/30/15 A Sweeter Summer
5/3/15 Bearing the Strain
3/13/15 Atomic Alterations
2/23/15 Tough Talks for Nuclear Delays

- **Risk reduced as settlement announced for VC Summer nuclear project schedule.** SCG announced a settlement agreement with the South Carolina Office of Regulatory Staff and the South Carolina Energy Users Committee (SCEUC) that would eliminate all contested issues and establish support for the approval of the revised construction and capital cost schedules for the VC Summer nuclear project under docket 2015-103-E. If approved, parties waive the right to appeal. See our "Atomic Alterations" and "Bearing the Strain" for details on these $1.1B of higher cost revisions, which include a $698M base capital increase and $374M of incremental escalation/AFUDC. Only $411M is being contested between the SCG and the construction consortium and SCG does not waive claims related to delay and other related contested costs.

- **Agreement includes 50 bps ROE reduction; impact begins mostly in 2017.** Settling parties agree to reduce the allowed ROE for VC Summer from 11.00% to 10.50%, to be applied prospectively under the Base Load Review Act after 1/1/16. We estimate this reduces the future revenue requirement by $14M over a 5 year period, with the -$0.06 EPS impact beginning after the Nov 2016 rate increase and weighted toward the first two years (peak construction period).

- **Two intervenors are not yet parties to the agreement.** Notably, neither the Sierra Club nor CMC Steel (the other two intervenors to the docket) have signed on to the agreement and they could still cross examine witnesses at the hearings scheduled to begin July 21. Management still hopes to sign both of them on, although we note that neither party has sent witnesses to prior hearings or acted much beyond filing for discovery. Recall that in Oct 2014, the SCEUC and the Sierra Club lost a SC Supreme Court appeal of a previous challenge to a $278M cost increase that had been approved by regulators.

- **Negotiations with the Consortium** over delays and $411M of costs are continuing. Management estimates $86M of liquidated damages as a possible offset, which is our understanding of the upper contractual limit to such damages. Management has described the talks as "tough" and we note that the EPC contract provides for arbitration in the event of a stalemate. Ultimately, litigation is always an option too down the line.

- **Consortium lays out possible VC Summer delay to June 2019.** In the last quarterly monitoring report, management noted that Unit 2 was being targeted for in-service for June, 2019, with Unit 3 expected a year behind in June 2020. This is over a year past the previous expectation of 4Q17-1Q18 and past the 18-month contingency period allowed by regulators that ends in Sept 2018. However, of 146 milestone items, only a few are actually past their deadlines by 18 months. The new schedule would appear to dovetail with that released by the consortium for SO's Project Vogtle, with an 18-month delay to 2Q19 for Unit 3 and 2Q20 for Unit 4. However, neither utility has agreed to the consortium's initial take on schedule, costs and negotiations, litigation, and mitigation efforts continue.

- **Holdco could lose investment grade rating; negotiations with consortium are being watched by the rating agencies.** While the utility's debt rating is expected to maintain investment grade levels, management acknowledged that construction delays are likely to cause some ratings slippage at both the operating company and holding company levels. According to management, the lack of a positive outcome in the consortium negotiations (particularly a shorter schedule) would "probably" cause the Holdco to slip below investment grade, despite $400M of cash recently added from the sale of CGT/SCI. The Holdco is currently on negative outlook at S&P (BBB) and Fitch (BBB+), and is stable at Moodys. Management also gave the impression that equity issuance to defend the rating would be unlikely as the Holdco won't need to issue or refinance anything until 2020 (emphasizing that operating company debt to fund construction will certainly remain investment grade). In particular, Moodys has highlighted the need to maintain FFO/Debt above 13%, which management sees as unlikely over

the next two years. While the BLRA provides for recovery of financing costs during construction, the plants must be in service to begin receiving cash for depreciation. The problem appears to be increasing balance sheet stress caused from this lack of capital recovery during an extended construction period.

- **No ratecases through 2017 despite delay and no equity through 2016.** With $400M of after-tax proceeds from the sale of CGT/SCI to D received in 1Q15, management terminated plans to issue any secondary equity in 2015/16 and will issue only $14M if DRiP this year as well. Due to the timing of redeployment into VC Summer and other capex, the transaction will be -$0.04 dilutive this year buy is expected to turn +$0.04 accretive by the end of 2016. Management's revised long-term 3%-6% EPS growth guidance is a few pennies above previous guidance.

- **Looking for an update to nascent ratebased distributed solar program.** SCE&G plans to build 95 MW by 2020 (~2% of peak load) in conjunction with Act 236, starting with 10 MW in 2015, with the first 3.8-MW project adjacent to corporate HQ. The overall target is split roughly 50/50 between utility and non-utility (commercial/residential).

- **Preparing wider solar efforts for beyond ITC expiration:** Consistent with peers like SO, mgmt appears poised to get *more* involved in solar investments after the expiration of the 2016-ITC. We look for a ratebase approach to be adopted in ~2017 timeframe.

- **Solar penetration poised to increase?** Following Act 236, we look for solar lease companies to get increasingly involved in the state, working off a base of just ~300 customers today in commercial/residential all together. We see 2015/16 growth as more meaningful as solar leasing companies compete to quickly add MWs ahead of ITC expiration.

- **Look for a cost shift solar report later this year.** We look for the SC PSC staff to release a report on the 'cost shift' of solar associated with net metering in SC by year end. This would appear to advance the case for reducing net metering compensation, already a hot button issue in NC with Duke Energy.

Estimating the Financial impact of Nuclear delays on the Consortium

Based on SO and SCG filings, we've summarized our thinking on the impact of nuclear construction delays for the Consortium building both SCG's VC Summer ad SO's Project Vogtle. Both AP 1000 projects are nearly identical and under construction by the same Consortium of Toshiba's Westinghouse and CB&I.

On March 12, SCG filed with SC regulators its special request for approval of its 55% ownership of increased costs associated with the VC Summer Units 2&3 new nuclear construction project. Importantly, management continues to dispute $411M (see table) of the incremental delay costs as presented by the WEC/CB&I Consortium and remains in negotiations that are eventually expected to result in downward adjustments (within future BLRA filings) after an agreement is reached. Furthermore, as noted below, SCG's escalation and AFUDC should decline as well in tandem with any reduction to these disputed costs. Talks have been described as "tough".

Figure 156: Incremental Costs in Special 3/12/15 BLRA request

Incremental Costs in Special 3/12/15 BLRA request		
Base Project costs ($M)		
Delay and Other EAC costs - **contested**	$	411
Delay and Other EAC costs - not contested		72
Change orders		57
Owner's costs from delay		214
Owner's costs not from delay		31
Liquidated damages provision		(86)
Total Base Project costs (2007 dollars)	$	698
Escalation	$	332
AFUDC		42
Total Increase ($M)	$	1,072

Source: Company filings

In the table above, there is $411m of contested capital plus $72m non-contested plus $57m design changes. Of this amount only the $411m is contested and could wind up as a liability of the Consortium. In addition to these capital costs, there's also $332m of escalation and another $42m of AFUDC from the delays, of which a portion will be borne by the Consortium. For this, we would apply a 2/3 rule and assume another $250m is the Consortium responsibility. That's a total of $411 plus $250 = $661m estimated Consortium liability plus another $86m liquidated damages to compensate for owner's costs = $747m total possible Consortium liability.

For SO, much less is known about the Consortium's extra costs because the contract is turnkey and Georgia Power's VCM 12 reports only the costs borne by Georgia Power, not the contractors. An ongoing lawsuit against the owners from 2012 indicates $900m of higher costs tied to alleged NRC scope and regulatory changes that were being borne by the Consortium back then. To this, add another amount (as a swag, take $100M) for rebar changes that were made after the lawsuit was filed. Simplified, SO and the owners continue to assert that these costs are not the result of scope changes and therefore the Consortium's responsibility. The lawsuit remains pending with a possible trial date later this year or early 2016. It is our understanding that a settlement may be possible should the Consortium members reach agreement among themselves over their internal split of responsibility. If one assumes that Vogtle's cost increases are similar to those of SCG's VC Summer, then one could add the increase in VC Summer to the $900m for a rough estimate. We note that before the latest delays, SCG used to estimate ~$200m higher capital costs, so the latest delays represent an increase of about $339m. Hence, for Vogtle, that would roughly indicate an increase for the consortium of $900m plus $339m = $1,239m. Then add another $240m liquidated damages (as indicated in the latest Georgia Power filing VCM 12) to get to ~$1.5B. For escalation, VCM 12 indicated a modest $99m decline for SO, so this is probably not an additive factor.

Overall, we would estimate total possible Consortium liability above the original EPC contracts of $747m plus $1.5B = ~$2.25B, of which $900m is in litigation with Georgia Power, $325m is potential liquidated damages, and the remainder is being disputed/negotiated. We do not know how that would be split between Westinghouse and CBI as this is an internal matter related to their contractor agreement. As we've written previously, our latest meeting with Georgia regulator Tim Echols indicated that Georgia regulators fully expect Toshiba to support Westinghouse, but that wasn't a legal opinion. For more details, please see our

recent reports SO 4/30 Holding Our Breaths for a Deal and SCG 5/3 Bearing the Strain.

Delineating the 111d opportunity

South Carolina has a 51% reduction target under EPA rules – the highest in the nation. This is largely because the EPA baseline assumes that the new nuclear units under construction were already operational, and thus cannot be used as offsets. SCG plans to retire 6 coal plants by the time the new nuclear comes on line. The capacity mix is expected to shift from 41% coal and 12% nuclear in 2013, to 32% nuclear and 27% coal by 2020 (with an estimate of dispatch to be 45% coal and 25% nuclear in 2013 to 58% nuclear to 23% coal by 2020). From an actual achieved emissions perspective, this would mean that the higher nuclear dispatch at the expense of coal would reduce emissions by ~20% still leaving significant reduction work to be done unless the baseline is changed to exclude the nuclear plant.

Under SB 1189, SCG needs to add 100MW of utility-scale solar to its system, and another 100MW of distributed solar on commercial/residential rooftops by 2020. Management said they are open to both the option of PPAs or owning the assets themselves, although we got the sense that management may prefer PPAs due to the inefficient use of tax credits within the ratebase construct.

We estimate ~$300-400mn annual free cash flow in 2019/20 once VC Summer is online. This could potentially be put to use in growing the electricity/gas distribution business and also to meet renewables targets, although in the first years, SCG will likely use the cash to purchase the Santee Cooper stake (subject to PSC approval). Overall, we do not expect any need for equity issuances for many years once the plant is online. SCG has also started adding on the transmission side in North Carolina, and this should eventually drive a ratecase some years down the line.

Economic growth still modest but improving

Economic growth in the Carolinas and SCG's territory continues to be modest, with unemployment trends in the region (5.6% for SCG jurisdiction) stabilizing after several years of falling along with the national average, now at 5.5%. Customer growth continues to improve, particularly at the gas LDCs, where SCE&G Gas and PSNC have each grown over 2.3% for the past 5 quarters and SCE&G Electric grew 1.5% (1.3%-1.5% over 5 quarters). Accounting for conservation and energy efficiency, weather adjusted total retail electric sales over the trailing 12 months were flat at 0.0%, with much stronger industrial growth of +3.3% offset by contraction in residential sales at -2.0% and commercial electric sales of -0.7%.

We note the apparent weakness that appears to have hit all levels of retail kWh sales (see table above) in the latest TTM, although this calculation is likely skewed a bit due to the difficulty in weather normalizing the effect of the Polar Vortex in 1Q14.

Figure 157: SCANA Customer Growth and kWh Sales Growth %, 1Q13-1Q15

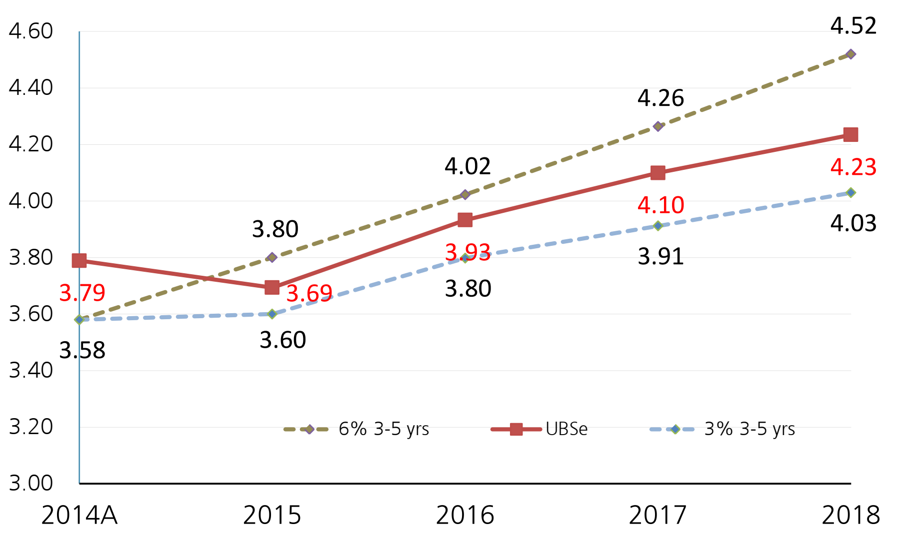
	Weather Adj Retail kWhs Sales (TTM)				Cust Growth (YoY each Qtr)		
	Residential	Commercial	Industrial	Total	SCE&G Elec	SCE&G Gas	PSNC
Mar-15	-2.0%	-0.7%	3.3%	0.0%	1.5%	2.9%	2.6%
Dec-14	-1.2%	0.0%	3.9%	0.6%	1.4%	2.8%	2.5%
Sep-14	-1.1%	-0.1%	4.2%	0.7%	1.3%	2.5%	2.5%
Jun-14	-1.5%	0.1%	3.7%	0.5%	1.4%	2.3%	2.3%
Mar-14	-0.8%	-0.4%	3.3%	0.5%	1.3%	2.4%	2.3%
Dec-13	-2.3%	-1.4%	3.1%	-0.5%	1.2%	2.4%	2.3%
Sep-13	-1.8%	-1.2%	1.6%	-0.6%	1.3%	2.2%	2.0%
Jun-13	0.1%	0.6%	-0.2%	0.2%	0.8%	2.0%	2.0%
Mar-13	2.5%	0.7%	0.5%	1.4%	0.8%	1.8%	2.0%

Source: Company filings

Maintain estimates; no credit for higher VC summer spending yet

On the 1Q call, management reiterated 2015 guidance of $3.60-$3.80 vs UBSe $3.69 and cons $3.72). LT growth guidance remains 3%-6% off a 2014 weather normalized base of $3.58. We note that 2015 guidance includes 1x -$0.04 of temporary dilution from the timing of redeployment of proceeds from the sale of CGT/SCI to D, expected to close in 1Q. Redeployment into the VC Summer nuclear project and other capital needs will happen over time as the elimination of originally planned equity issuances for 2015 and 2016 increasingly affect EPS, with the expected +$0.04 of expected transaction accretion in full effect by the end of 2016 (a +$0.08 overall swing over two years).

Figure 158: UBSe vs EPS Implied Guidance from 3%-6% Growth off Weather Normalized 2014A



Source: Company filings, UBS estimates

Our estimates are unchanged and now reflect -$0.03 for a lower ROE as announced in the settlement (mostly 2017 and beyond). We have not yet reflected any possible benefit from higher nuclear capex and CWIP pending the outcome of the special BLRA petition and negotiations with the consortium. We continue to see some incremental pressure to 2017+ EPS projections on the back of the delayed nuclear schedule and avoidance of rate cases, with added need to maintain cost controls while the project construction is ongoing (management

remains committed to avoiding another case during construction, which is delayed).

Figure 159: UBS Estimates for SCG, 2013-2018E

	2013A	2014A	2015E	2016E	2017E	2018E
SCE&G	$ 2.81	$ 3.23	$ 3.15	$ 3.35	$ 3.43	$ 3.56
PSNC	$ 0.35	$ 0.39	$ 0.41	$ 0.43	$ 0.48	$ 0.49
Other	$ 0.23	$ 0.17	$ 0.14	$ 0.15	$ 0.19	$ 0.18
Consolidated	**$ 3.39**	**$ 3.79**	**$ 3.69**	**$ 3.93**	**$ 4.10**	**$ 4.23**
CAGR vs 2014 weax norm $3.58			3.2%	4.8%	4.6%	4.3%
Guidance Range		*$3.60 -$3.80*				
Prior UBSe		*$ 3.79*	*$ 3.69*	*$ 3.93*	*$ 4.10*	*$ 4.23*
Street Consensus		*$ 3.79*	*$ 3.71*	*$ 3.89*	*$ 4.13*	*$ 4.59*
Long-Term Guidance (3-6% Range)		*3% -6% L-T EPS growth off 2014 $3.58*				
High		$ 3.58	$ 3.80	$ 4.02	$ 4.26	$ 4.52
Med		$ 3.58	$ 3.70	$ 3.87	$ 4.04	$ 4.22
Low		$ 3.58	$ 3.60	$ 3.80	$ 3.91	$ 4.03

Source: UBS estimates, Company filings, FactSet

Valuation: Raise PT $1 to $56

We value on a SOTP based on 2017E peer utility P/E. For the improved regulatory risk profile from the recently announced BLRA settlement, we now apply only a 7% discount to peers vs 10% prior. This is offset by -$0.03 in 2017E for a lower ROE and a lower avg mult as well. Unregulated SCANA Energy Georgia is valued at 5X 2015E EBITDA. While utility operations outside of the nuclear project have been impressive (earning at the top end of allowed ROEs with improving customer growth and usage rates), we remain on the sidelines until better clarity on the execution risk for VC Summer Units 2 and 3. We believe timeline on getting sufficient clarity for investors to be comfortable is now 2016 at earliest, with SC PSC needing to bless any delay first. Moreover, with key years of capital spend in 2016 and 2017, we expect the delay to linger during this higher risk execution period.

Figure 160: SCG Sum of the Parts on 2017E

Scana Sum of Parts										
SCANA Corp Valuation			**Low Case**			**Base Case**			**High Case**	
Business Segment	**Valuation Metric**	**2017**	**Valuation Multiple**	**($s MM) Value**	**Peer Multiple**	**Prem/ Discount**	**Valuation Multiple**	**($s MM) Value**	**Valuation Multiple**	**($s MM) Value**
Regulated Business										
SCE&G Franchised Electric	P/E	$3.43	13.2x	$6,678	14.7x	-7%	13.7x	$6,932	14.2x	$7,185
PSNC	P/E	$0.48	14.4x	1,021	15.7x	-5%	14.9x	1,056	15.4x	1,091
SCG Utilities Equity Value				**$7,699**				**$7,988**		**$8,277**
Georgia Retail (Net of Corporate)	EV / EBITDA	$54	4.0x	$216			5.0x	$270	6.0x	$324
Total				**$216**				**$270**		**$324**
SCG Equity Value				**$7,915**				**$8,258**		**$8,601**
Fully Diluted Outstanding Shares (2017)				148				148		148
SCG Equity Value per Share				**$54.00**				**$56.00**		**$58.00**

Source: UBS estimates, Company filings, FactSet

Sempra Energy (Buy; $118 PT)

We estimate that Sempra will report 2Q15 adjusted EPS of **$0.97**, relatively flat with 2Q14 as the negative drag from SoCal Gas offsets growth elsewhere in the business. We see the quarter as slightly weak of consensus at $0.99. The Figure on the right below shows the magnitude of the difference between the 2014 as reported and pro forma results: application of seasonality factors has a material difference which is most pronounced in 1Q (positive) and 3Q (negative). For example, applying this change to 2014 historical would have a ~$100Mn favorable impact, or ~$0.38/sh. This has no impact of FY earnings or cash.

Strong earnings beat driven entirely by a change in accounting methodology which makes earnings more volatile like a LDC.

We flag this is the second quarter of the seasonality adjustment for SoCal Gas, making this quarter once more a bit challenging in comparability. On an equivalent basis, we assume growth at SoCal of +$0.02 (straight seasonality impact would have resulted in a -$0.16 headwind).

1Q14 SoCal earnings represented ~25% of FY earnings on this 'smoothed' as-reported basis. On a pro-forma basis 1Q14 would have represented over 50% of FY earnings for SoCal.

We expect more meaningful growth from Mexico and South America; we flag through the investment period, IENova does not record AFUDC based on IFRS accounting. In contrast, Sempra is allowed to book more of a gradual earnings increase predicated on development at the SRE Mexico segment.

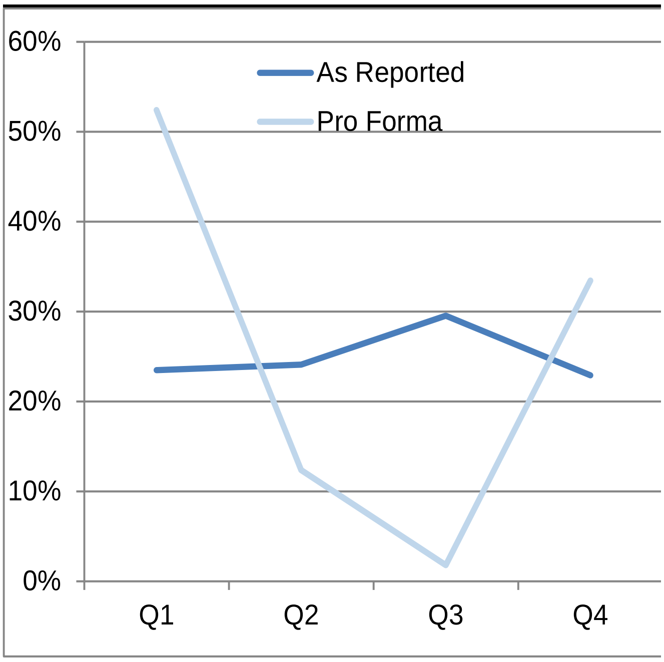
US Power & Gas should remain relatively stable, with management having guided to relatively flat results YoY.

Figure 161: 2Q15 Earnings Walk

SRE 2Q15 Earnings Walk	EPS
2Q14A Adj EPS	**$1.08**
SDG&E	$0.03
SoCal Gas	($0.14)
Sempra International	
South America	$0.02
Mexico	$0.02
F/X Impact	($0.01)
US Power & Gas	
Renewables	($0.02)
Natural Gas	$0.01
Parent	($0.01)
Dilution	($0.01)
2Q15E Adj EPS	**$0.97**
2Q15E EPS - SoCal Acct. Δ	**$1.15**
One-Time SoCal Gas Tax	$0.03
2Q15E Consensus	**$0.99**
2015 Guidance	**$4.60-$5.00**
2015 UBSe	**$4.80**
2015 Consensus	***$4.86***

Source: Company Filings, FactSet and UBS Estimates

Figure 162: SoCal Gas 2014 Seasonality



Source: Company Filings and UBS Estimates

For additional context, please refer links to relevant recent reports below:

7/6/15 Watching the Sparks and Sparklers (page 8: "The Next Round of California Capex")
6/19/15 The Northern Opportunity
5/7/15 It's Going To Be More MLP-Like, After All
4/6/15 Gassing Up for 11% Growth
3/16/15 Revitalizing the Mexican Midstream Opportunity
3/10/15 Supersizing Sempra

[12/17/14 Lost El Encino II Bid Still plenty of growth projects ahead, despite some likely delay]
[12/10/ Limited Risk of Slipping on an Oil Spill]
[11/26 Full Steam Ahead for Cameron]
[11/20 The Other Side of the LNG Debate (Incl. Conf Call Transcript)]

What's New With Sempra?:

- **2015 adjusted EPS guidance was last reaffirmed** on the 1Q call at $4.60-$5.00. We don't expect a change.

- **Busy summer with $1.3Bn capex up for bid in Mexican CFE process.** Sempra is bidding on $1,325Mn of CFE pipeline development opportunities this summer and was most recently awarded a contract for San Isidro-Samalayuca ($147Mn) on July 14. While this is a relatively short piece of pipe with low capital requirements, we note its strategic location as a connector for the Samalayuca – Sásabe ($825Mn) project that will be awarded in August. An announcement is also expected in August for Tuxpan-Tula ($400Mn). Bidding for another $600Mn of spending for the Baja Sur pipeline is in process with further details expected on the 2Q call. The Colombia – Escobedo pipeline had been expected to be auctioned this year too but it does not appear to have made the latest procedural list and could be on hold until next year. These next few months will be critical in shoring up confidence in IENova's ability to win bids in an increasingly competitive market.

Ienova was most recently awarded a contract for the strategically important San Isidro-Samalayuca project ($147Mn) on July 14.

Figure 163: CFE Pipeline Bid Opportunities

Projects Not Yet Awarded	Capex ($Mn)	Status	CODe
San Isidro – Samalayuca	147	Won the contract on July 14	2017
Mérida – Cancún	460		2016
Texas – Tuxpan	3000		2018
Tula – Villa de Reyes	420		2017
Tuxpan – Tula	400	Bid in June 2015; Award in Aug	2017
Samalayuca – Sásabe	825	Bid in July 2015; Award in Aug	2017
Colombia – Escobedo	370	TBD (on hold until 2016?)	2017
Jaltipán – Salina Cruz	640		2017
Los Ramones – Cempoala	2000		2017
Ville de Reyes – Guadalajara	545		2017
La Laguna – Centro	885		2018
Lázaro Cárdenas – Acapulco	450		2018
Salina Cruz – Tapachula	435		2018
Baja Sur	600	TBD	2017
Total	**11,130**		

Source: Company Filings

- **SDG&E filed its Distributed Resource Plan on July 1** along with the other investor-owned utilities. SDG&E's plan is less capital intensive than either PG&E's or Southern California Electric's (SCE) given an overall newer system.

- **Cameron receives FERC approvals for Train 2 construction.** For proposed Trains 4&5, we still expect a FERC application by late-2015 or 1Q16 as the company works to secure enough interest from customers (binding or not) to warrant the expense of the engineering studies and design work needed for the filing. Later on, we expect a Final Investment Decision (economic point of no return) once a higher level of binding commitments is received, likely to be contingent on some level of completion of the plant. Our colleague Steven Fisher notes that Engineering Procurement & Construction (EPC) contractor CBI

has reported lower steel and other supply costs, which should give them "breathing room" within the confines of their lump-sum contract.

- **Signed MOU with Woodside for Port Arthur.** The company signed a non-binding Memorandum of Understanding (MOU) with an affiliate of Woodside Petroleum Ltd. To discuss and assess the potential development of Port Arthur as an LNG export terminal. SRE pre-filed the project with FERC and filed for an FTA-export permit with the DoE in March 2015.

- **Expect further REX updates** now that the binding open season completed with 0.7 BCF/day of capacity now contracted for 15 years. The expansion will be achieved primarily through compression and be in service by yearend 2016. SRE's investment is $530M and is expected to generate about $10M of annual earnings (already in the base plan).

- **No significant renewables acquisitions in the quarter.** Copper Mountain Solar 2&3 are now both fully in service, bringing the total operating portfolio to 970 MW. SRE also recently acquired the 78-MW Black Oak Getty Wind project in Minnesota, which is incremental to the base investment plan. The project is contracted to the Minnesota Municipal Power Agency for 20 years and is expected to be in service by yearend 2016.

Distribution System Upgrade Plans Filed

The SDG&E plan emphasizes the principal of "equality of access" for all customers regardless of income level.

On July 1, all three publicly owned California utilities filed their Distribution Resource Plans (DRP) as required under AB 327, the law that was passed in Oct 2013 to direct the development of plans for future distribution resource management and integration as well as the redesign of the state's rate tier structure and new net metering policies. The purpose of these plans is to eventually create a system that can easily accommodate the "plug and play" of "distributed energy resources" (DER), such as solar, wind, demand response, energy efficiency, battery storage, electric vehicles, and other behind-the-meter energy supply devices. Rather than the current system designed around central station one-way flow out to customers, the system of the future would be able to manage and optimize two-way flows from a wide variety of distributed generation and efficiency equipment. The plans are required to evaluate locational benefits and costs of DERs, identify new tariffs, contracts, barriers to deployment of new technologies, and determine any additional utility spending necessary to upgrade the grid with the goal of yielding net benefits to ratepayers.

The critical point to emphasize is that these plans form the basis for future capex growth for these companies. While spending levels will still be established through the GRC process, the DRPs provide the outlines for capex plans to be presented through these respective filings – and add credibility to future year continued ratebase growth for California utilities.

Figure 164: Scenarios for Statewide Amounts of Distributed Energy Resources Deployment by 2025

Statewide Amounts of DER Deployment by 2025	Scenario 1 "Normal growth"	Scenario 2 "High Growth"	Scenario 3 "Very High Growth"
Base Load	60,109 MW	60,109 MW	60,109 MW
Solar PV (nameplate AC)	4,812 MW	5,498 MW	13,792 MW
AAEE (annual)	22,565 GWh	36,068 GWh	36,655 GWh
Demand Response	2,176 MW	3,570 MW	5,100 MW
CHP (annual)	13,877 GWh	21,132 GWh	32,112 GWh
EV (annual)	4,877 GWh	7,026 GWh	7,026 GWh
Storage (D&C)	654 MW	654 MW	1,543 MW
Storage (T)	700 MW	700 MW	1,651 MW

Source: Southern California Edison Distributed Resource Plan

Sempra's utility SDG&E's plan includes a three-scenario comparison of increasing aggressiveness, as does the plan for neighboring utility Southern California Electric (we include SCE's statewide projections in the table above). It also proposes a memo account for spending prior to its next general ratecase. The SDG&E plan emphasizes a principal of "equality of access" for all customers regardless of income level. With a generally newer system than SCE, the SDG&E plan has overall less work to do with likely less capex over time (vs SCE's preliminary projection for $1.8B-$3.1B through 2020). SDG&E's plan also discusses "locational net benefits" and notes some physical limitations to a distributed grid that need attention, including:

- Thermal limits of conductors, transformers, and other system components
- Voltage limits, including both at steady state as well as a fluctuating condition at the local level
- Protection limits on existing fault detection equipment, such as feeder breakers, switches, reclosers, erc…

SDG&E proposes several small demonstration projects of PV, inverter, dynamic controllers, storage and voltage regulation to be executed through 2020.

Reducing EPS Estimates slightly for a lower commodity deck

We present our EPS estimates below which are reduced for lower power prices affecting their small merchant portfolio.

Figure 165: EPS Estimates

Net Income	2014E	2015E	2016E	2017E	2018E	2019E	2020E
UBSe EPS	$4.72	$4.80	$5.04	$5.36	$6.41	$7.34	$8.07
Prior UBSe		*$4.80*	*$5.07*	*$5.40*	*$6.47*		
Guidance - EPS							
Consensus EPS		*$4.86*	*$5.20*	*$5.59*	*$6.38*	*$7.38*	

Source: Company Filings, FactSet and UBS Estimates

Valuation: Reduce PT $2 to $118 for lower ests and a lower utility peer P/E multiple; Reiterate Buy

Below we present our summary Sempra sum-of-the-parts valuation. We base our sum of the parts on 2017E peer utility multiples as well as industry average EV/EBITDA for pipelines, storage, and renewables. We assume a 50% probability for incremental solar project EBITDA through 2017.

Figure 166: Sempra Valuation

Summary Sempra Sum of the Parts Analysis - UBSe Segment	Primary Methodology	Valuation/ Share
Sempra Natural Gas		
Storage, Cameron (Import & Interstate), and REX	7-12x EV / EBITDA	$6.03
Gas LDCs	16x P/E	$0.80
Total Sempra Natural Gas		**$6.83**
Sempra US Power & Renewables		
Solar	14.5x EV/EBITDA	$4.43
Wind	8-15x EV/EBITDA	$0.79
Accelerated Depreciation Tax Shield and Other	NPV	$5.76
Total Sempra US Power & Renewables		**$10.98**
Cameron LNG Export Project		
Trains 1-3	NPV of 9x EV / EBITDA and MLP Accretion	$12.97
Accretion due to GP/LP Structure in MLP		$4.67
Trains 4-5		$4.02
Total Cameron LNG Export Project		**$21.67**
California Utilities		
SoCal Gas	17x P/E (1x premium)	$26.40
SDG&E	16x P/E (1x premium)	$35.64
Total California Utilities		**$62.04**
International		
SRE Mexico/IENova	Various	$26.74
Chile (Chilquita) - Unlisted	11x P/E	$3.80
Peru - Listed	Public Value	$5.36
Total International		**$35.90**
Less: Parent Debt	Book Value	($19.34)
Grand Total Sempra		**$118.09**

Source: Company Filings, FactSet and UBS Estimates

Southern Company (Sell; PT $41)

Expect an in-line quarter with most of the focus on Kemper settlement negotiations, the recent Vogtle cost recertification, and regional economic growth.

Main drivers for the quarter include -$0.07 for weather normalization and -$0.08 of higher O&M vs last year's Polar Vortex.

We expect SO to report 2Q15 $0.69 vs consensus $0.69 and management guidance of $0.69. The main drivers for the quarter include -$0.03 for weather normalization and -$0.03 of higher O&M, offset by +$0.03 of non-weather sales growth, +$0.03 of rate relief (including a penny or two from Rate Stabilization and Equalization in Alabama). We assume Southern Power earnings grow a penny from incremental solar projects in the last 12 months. We do not expect any change to current 2015 guidance (provided on Feb 4) of $2.76-$2.88 vs UBSe $2.85 and consensus $2.83 as well as long-term EPS growth guidance of 3%-4% off the 2015 range.

Figure 167: SO 1Q15E vs 1Q14A Walk

2Q15 Earnings Walk		EPS
2Q14A Adjusted EPS		**$0.68**
Return to Normal Weather from 2Q14		($0.03)
Weather in 2Q15		$0.00
Retail sales economic growth (Industrial Sales)		$0.03
Wholesale Ops		($0.02)
Rate Relief		
GA- Base Rate Increase Jan 1 2014	34.0	$0.01
GA- Nuclear Cost Recovery	6.7	$0.00
MS Power - PEP	-	$0.00
MS Power- AFUDC on Kemper	-	$0.00
Gulf Power	5.0	$0.00
Alabama Power RSE	45.3	$0.02
Southern Power		$0.01
Interest Expense		($0.00)
Non-fuel O&M		($0.03)
Other income and deductions		$0.02
D&A		$0.01
Share Dilution		($0.01)
2Q15E Adjusted EPS		**$0.69**
2Q15 Guidance		*$0.69*
Consensus		*$0.69*

Source: UBS Estimates, Company filings

For further context, please refer to our recent notes:

7/10/15 Getting Messy in Mississippi
4/30/15 Holding Our Breaths for a Deal
2/5/15 Still Struggling

What's new with Southern?

Looking for a rate settlement before Staff files a recommendation in early August.

- **On July 3, the Mississippi Supreme Court ordered the PSC to direct Mississippi Power to refund the $294M CWIP balance plus interest (total $350M) back to customers.** This construction work in progress (CWIP) account had been collected to help fund and mitigate rate shock for the Kemper Integrated Coal Gasification Combined Cycle (IGCC) project. This effectively takes of the table the utility's preferred rate plan to keep the balance and increase rates only an incremental 6% once in service. On July 7, the PSC ordered the utility to submit a refund plan within 14 days and the PSC is expected to issue a decision on it by Aug

18, including a customer option to receive either a bill credit or a check within 90 days (mid-November). Any cash refunds are likely to be paid from the utility balance sheet out of short-term debt unless mitigated as bill credits over some agreed period of time.

- **Still no need for equity.** Management continues to emphasize that their capital plan already envisioned some built-in contingency for additional Kemper costs and that no additional equity would be required in light of recent announcements. In addition to the coming CWIP refunds, the Southern Mississippi Electric Power Association (SMEPA) withdrew from its originally planned 15% ownership of Kemper on May 20, requiring SO to refund its $275M deposit plus interest (a total of $300M). This payment was made from SO parent and was recorded as debt on Mississippi Power's balance sheet. SMEPA had been set to take on a 15% stake in the project, estimated to be about $600M plus $110M of AFUDC at completion (plus other proportional inventory, prepayments, and regulatory assets). Considering that Kemper and Vogtle are expected to throw off significant cash flow upon completion, the company is inclined to ride out the interim charges with short-term debt funding. However, a significant increase in Southern Power's investment budget could require an incremental equity boost.

Contingencies should hold for now?

- **Mississippi Power sitting on higher leverage for now.** The $300M SMEPA payment was made at the SO parent level and will sit as debt on utility Mississippi Power's balance sheet. Management does not intend to provide any additional equity support to the utility, leaving any improvement of the utility's credit rating to the outcome of the ongoing ratecase. On June 5, Fitch downgraded the utility's long-term issuer default rating to BBB+ from A- on Kemper concerns after the Supreme Court order.

- **Mississippi regulatory Staff has 80 days from the company's May 15th ratecase filing to file its recommendation** for cost recovery of the Kemper project to the Public Service Commission, <u>thus setting up an expectation for a settlement prior to early August.</u> A final order is due at the 120-day mark on Sept 12, otherwise the filed request for a 40% rate increase will take effect. All three commissioners are running for re-election this November, with two indicating that they will not seek a new term. This lends an air of urgency to have a deal in place before a new regime takes over.

A final order is due at the 120-day mark on Sept 12, otherwise the filed request for a 40% rate increase will take effect.

- **Kemper construction update:** SO continues to project Kemper achieving substantial commercial operation by April 2016. From 2013 through March 31, 2015, SO recorded pre-tax charges totaling $2.06B ($1.27B after tax) for revisions of estimated costs expected to be incurred for Kemper above the cost cap (net of federal grants). No major increases in net unrecoverable costs in the May status report (filed July 2), with only $10M of higher costs vs April. This included $25.4M of higher EPC cost and another $29.6M of higher pre-commercial operations expense offset by -$27M of reduced schedule risk and -$20.2M of reduced contingency. We note the contingency fund stands at $45.6M. First-fire of both gasifiers was successfully tested in March, a major milestone, and air flow testing for Trains A and B were completed in April and May, respectively. The next technical milestones are fluidization trials and lignite delivery

facility testing in August (delayed a month) and the first synthesis gas production which is planned for 3Q. The CCGT (operating on natural gas) had a 1Q equivalent forced outage rate of less than 1% and a capacity factor in line with the rest of the company's CC fleet.

- **Negotiations with the Westinghouse/CBI Consortium over the revised nuclear construction schedule for Plant Vogtle continue.** We emphasize that SO has accepted neither the delays nor the higher projected costs for the project and that both remain subject to possible mitigation as well as litigation and negotiation. A prior 2012 lawsuit over at least $900M of contested costs also remains active, with a trial possible in late 2015 or early 2016 should the parties fail to arrive at a settlement. It is our understanding that a dispute among Consortium members over the split of cost responsibility is currently one obstacle to a settlement.

- **Strong support for Vogtle nuclear construction in Georgia; more coming?** Commissioner Tim Echols expressed very strong continued support for Vogtle in our April meeting. His remarks were in lockstep with Commissioner Wise and emphasized that there is no cost cap for the project despite the PSC's recent decision not to "recertify" higher costs associated with delays. Instead, the PSC believes it's in the public interest to follow the original plan until the completion of Unit 3 in June 2019 to amend the currently certified $6.113B cost (from a March 2009 order). Regulators appear to have gone out of their way to emphasize that the "certified cost" does not in any way constitute a cost cap, and neither does the Stipulation in VCM 8. See GPSC docket # 29849. Echols also indicated a possible desire for an additional two nuclear units to help Georgia manage both fuel volatility risk as well as CO2 should these first two prove successful.

- **Expecting another "significant slug" of regulated solar** in Georgia next year. In July, SO began participating in a program to help Georgia customers choose and fund/lease residential solar.

- **In April, Commissioner Wise noted that Georgia Power is likely earning toward the top end of its 12% ROE band, "but that's ok."** The EPA's proposed Clean Power Plan (CPP) is expected to have a significant effect on the "economic vitality" of Georgia in its current form. In particular, Georgia appears to receive no credit for carbon reductions coming from the retirement of coal plants over the past few years as well as the construction of Vogtle.

No change to Estimates

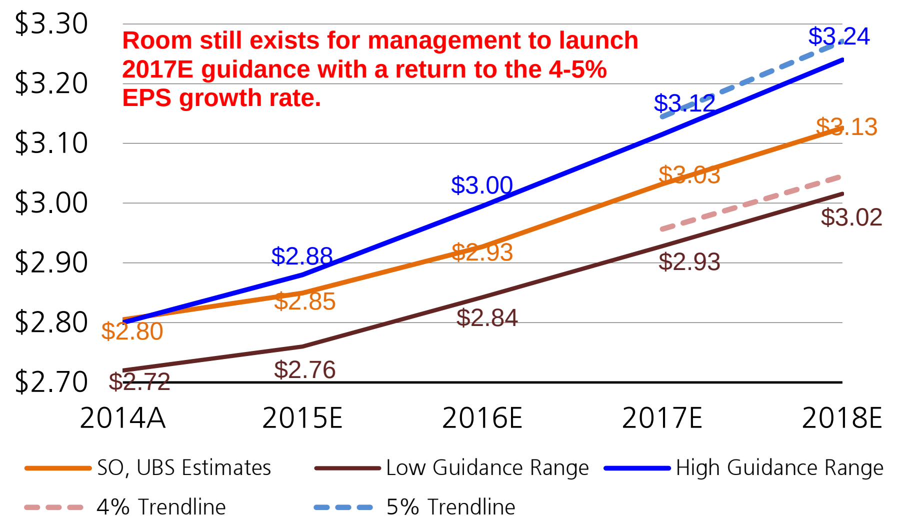
Our earnings estimates reflect an improved outlook for Southern Power on the heels of the Oklahoma wind acquisition offset by the -$0.03 ITC earnings cliff in 2017. We are slightly above the midpoint of guidance for 2015E. *Our revised estimates continue to imply a 3-year earnings CAGR at the bottom end of 3-4% contemplated long-term rate.*

Figure 168: UBS Updated Estimates for SO 2014E-2018E

SO EPS Estimates	2014A	2015E	2016E	2017E	2018E
Alabama Power	$0.85	$0.82	$0.82	$0.86	$0.90
Georgia Power	$1.37	$1.46	$1.51	$1.56	$1.58
Gulf Power	$0.16	$0.16	$0.16	$0.17	$0.18
Mississippi Power	$0.25	$0.23	$0.24	$0.27	$0.29
Southern Power	$0.19	$0.19	$0.20	$0.17	$0.18
Other	($0.01)	($0.00)	($0.01)	($0.01)	($0.01)
SO, UBS Estimates	**$2.80**	**$2.85**	**$2.93**	**$3.03**	**$3.13**
		1.6%	**2.7%**	**3.6%**	**3.1%**
Guidance Range		2.76-2.88			
3-year EPS CAGR ('15-'18)		3.1%			
Long Term EPS CAGR Guidance		3-4%			
Prior UBSe		*$2.85*	*$2.93*	*$3.03*	*$3.13*
Street Consensus		*$2.83*	*$2.94*	*$3.02*	*$3.10*

Source: UBS estimates, Company filings, FactSet

Figure 169: Updated UBSe EPS Estimates Relative to Guidance Expectations



Source: UBS estimates, Company filings

Valuation: Maintain $41 PT and Sell rating

Figure 170: SO valuation table (based on 2017E earnings)

Southern Company Valuation (UBSe)			**Low Case**		**Base Case**			**High Case**	
Business Segment	**Valuation Metric**	**2017E**	**Valuation Multiple**	**Per Sh. Value**	**Prem/ Discount**	**Valuation Multiple**	**Per Sh. Value**	**Valuation Multiple**	**Per Sh. Value**
Regulated Business									
Alabama Power	P/E	$0.86	13.7x	$11.79	0.00x	14.7x	$12.65	15.7x	$13.51
Georgia Power	P/E	$1.56	12.2x	$19.07	-1.50x	13.2x	$20.63	14.2x	$22.20
Gulf Power	P/E	$0.17	13.7x	$2.34	0.00x	14.7x	$2.51	15.7x	$2.68
Mississippi Power	P/E	$0.27	11.2x	$3.06	-2.50x	12.2x	$3.34	13.2x	$3.61
Southern Power (Contracted Merchant)	P/E	$0.17	12.7x	$2.20	-1.00x	13.7x	$2.37	14.7x	$2.54
Other	P/E	($0.01)	13.7x	($0.13)	0.00x	14.7x	($0.13)	15.7x	($0.14)
Southern Company Total/Implied		**$3.03**	***12.5x***	**$38.00**		***13.5x***	**$41.00**	***14.5x***	**$44.00**
Shares Outstanding					914	*Overall discount*			
Regulated Peer Group Multiple					14.7x	**-8.0%**			

Source: UBS estimates

Talen Energy (Sell; $18 PT)

Shares have fallen ~15% due to a weaker commodity curve in recent weeks but mgmt has started getting more aggressive on discussing its M&A plans with the media. While an accretive deal offers upside, we see the near-term PJM datapoints as absolutely critical given the magnitude of the sensitivities (we currently embed a probability-weighted ~$2 of value already).

We forecast Talen reporting adjusted 2Q15 EBITDA of **$160Mn** which consists of a full quarter for the PPL Supply portfolio and a one month (June) contribution from the recently acquired RJS assets. The Street expects adjusted EBITDA of $175Mn but there are only two divergent estimates ($250Mn and $100Mn). We caution investors that the initial headline number disclosed by Talen is likely to be just for this portion of the fleet rather than a typical 2Q run-rate. On a pro-forma basis (three months of the full portfolio) we estimate $202Mn, down slightly YoY vs our 2Q14E estimation and in-line with Consensus ($205Mn). There were Susquehanna unit outages in both 2Q14 and 2Q15; w expect a muted YoY impact.

Quarter generally looks fine with offsetting Susquehanna outages. We see a miss versus a thin Consensus.

Figure 171: TLN 2Q15 Earnings Walk

Talen 2Q15 Earnings Walk	EBITDA
PPL Supply	$155
RJS	$62
2Q14E Adjusted EBITDA	$217
PPL Supply (A)	$157
RJS Jan-May	$40
RJS June (B)	$2
2Q15E Pro-Forma EBITDA	**$200**
2Q15E Adj EBITDA (A) + (B)	**$160**
YoY Pro-Forma Decline	($17)
2Q15 Consensus	$175
2015 Guidance	**935-1,085**
2015 UBSe	**$1,008**
2015 Consensus	**$985**

Source: Company Filings, Thomson, and UBS Estimates

For more detail on these issues, please see our other recent reports:

6/4/15 Initiation: Choppy Waters on the Susquehanna
5/22/15 The 10 Key Talen Debates

What's new with TLN?

- **Commodity headwinds creates challenging start:** With Talen's formal update presentation only 45 days ago, we do not anticipate material new disclosures. We note that the hedging data was provided as of March 31 and there will be pressure on the outlook given the declines in power prices since then, particularly June/July's weakness. We do not anticipate a guidance reduction so soon after its first ever conference call as a public company, particularly with 2015 90% hedged but 2016 is far more exposed (29% hedged).

Talen is among the most sensitive to PJM power and capacity; power prices have not trended in the correct way as of late.

- **What did we learn from recent media interviews? That everything is still on the table.** With respect to M&A, CEO Paul Farr reiterated that the company is open to coal, gas, and nuclear but expected to add more gas

exposure. Farr specifically named AEP's generation assets and Energy Future Holdings (EFH)'s Luminant assets as potential targets.

Lastly Farr touched on Montour and seemed to indicate a stronger preference for the potential co-firing addition although no decision has been made yet. On the June update call management stated there was a "potential" to add co-firing capability with a ~12-mile gas lateral over to the TETCO Pipeline. While already compliant with the PA RACT regulations, the decision to add a gas line would largely be predicated on the economic merit of co-firing.

- **Potential to divest Colstrip to Puget Sound:** Following recent legislation in Washington state, we see the potential for Puget Sound Energy to acquire an ownership in the Colstrip coal plant from Talen, in turn shutting down Units 1&2 but also acquiring it's stake in Unit 3. The key question remains what the legacy environmental liabilities are associated with inherited Units 1&2. We see Talen as a ready seller of the assets given its divestment of adjacent non-core Western assest.

- **Shedding renewables portfolio but sale driven mostly by attractive pricing; still open to renewable investment:** On Friday 6/26 Talen announced the sale of its 65MW renewables portfolio to Energy Power Partners for $116Mn. Per S-1 disclosures, over the last five years the assets generated less than 2% of PPL Energy Supply's operating income (<$20Mn annually). The portfolio sold notably did not include any hydro assets: Holtwood and Wallenpaupack hydro assets are in one of the divestiture packages. This sale is not unexpected as Talen disclosed that it was considering divesting the fleet during the IPO process. Management indicated previously that renewable investment could be part of its strategy and it remains to be seen how this transaction fits into the larger plan for Talen. Given the weaker free cash flow profile, heavy coal exposure, and taxable income, we see investing in renewables as a logical move. It is unlikely that Talen has the same lofty renewable aspirations as NRG Energy does but we would not be surprised to see additional investment here. Talen has indicated that if it does pursue renewables it would be a larger basis rather than the collection of smaller assets we detailed out below.

Talen sells its renewable portfolio which represented ~2% of assets and a similar level of operating earnings.

The press release states that the sale covers 65MW and 25 projects versus the S-1 disclosure of 25MW of renewables at PPL Supply across NH, NJ, PA, and VT. Below we detail out 19 PPL Supply renewable projects consisting of 61MW, with the majority of projects in the 3MW range.

Figure 172: Talen Renewable Portfolio

Talen Renewables Portfolio							
Power Plant Name	Owner	Owned Capacity (MW)	Fuel Type	Plant Type	Year First Unit in Service	ISO(s)	State
Allenwood (PPLRE Lycoming County Landfill Project)	PPL Renewable Energy	3	Landfill Gas	Operating	2012	PJM	PA
Colebrook Landfill	PPL Renewable Energy	1	Biomass Waste	Operating	2010	New England	NH
Crayola Solar Park	PPL Renewable Energy	1	Solar	Operating	2010	PJM	PA
Cumberland County Landfill	PPL Renewable Energy	5	Biomass Waste	Operating	2008	PJM	NJ
Frey Farm Landfill	PPL Renewable Energy	3	Landfill Gas	Operating	2006	PJM	PA
Glendon Plant	PPL Renewable Energy	3	Landfill Gas	Operating	2011	PJM	PA
Greater Lebanon Refuse Authority Landfill	PPL Renewable Energy	3	Biomass Waste	Operating	2007	PJM	PA
Hill at Whitemarsh	PPL Renewable Energy	2	Natural Gas	Operating	2007	PJM	PA
IESI Blue Ridge Landfill	PPL Renewable Energy	6	Landfill Gas	Operating	2013	PJM	PA
Lycoming County Landfill Project (PPL Renewable)	PPL Renewable Energy	3	Landfill Gas	Operating	2012	PJM	PA
Moretown Landfill	PPL Renewable Energy	3	Biomass Waste	Operating	2008	New England	VT
Northern Tier Landfill	PPL Renewable Energy	2	Biomass Waste	Operating	2009	PJM	PA
Pennsauken Landfill	PPL Renewable Energy	3	Landfill Gas	Operating	2004	PJM	NJ
Pennsauken Solar	PPL Energy Supply LLC	2	Solar	Operating	2006	PJM	NJ
Schering-Plough Campus Solar Facility	PPL Renewable Energy	2	Solar	Operating	2009	PJM	NJ
Shippensburg (Cumberland County) Landfill	PPL Renewable Energy	6	Biomass Waste	Operating	2009	PJM	PA
Turkey Point Wind Project (Frey Farm Wind)	PPL Renewable Energy	3	Wind	Operating	2011	PJM	PA
United Water New Jersey Facility	PPL Renewable Energy	8	Natural Gas	Operating	2004	PJM	NJ
Warren County Solar	PPL Renewable Energy	2	Solar	Operating	2012	PJM	NJ

Source: SNL Energy

Commodity mark-to-market offset by reduced cost assumptions

We have refined our estimates following our initiation last month to reduce operational and fuel costs; however, this is generally offset by the contraction in power prices since early June. The net impact is a 2% reduction in 2016E with 2017E immaterially changed.

Figure 173: Updated Talen Energy EBITDA Estimates

Talen Energy EBITDA Summary	2013A	2014A	2015	2016	2017	2018	2019
PPL Supply	$646	$724	$712	$609	$381	$460	$539
Raven Power	$0	$136	$127	$117	$113	$126	$130
Sapphire Power	$0	$40	$42	$36	$25	$25	$26
Topaz/Jade Power	$0	$10	$19	-$3	$6	$7	$10
Subtotal		$911	$900	$759	$525	$619	$705
Synergies and Other	$249	$4	$108	$150	$191	$171	$171
Total Adjusted EBITDA	**$249**	**$915**	**$1,008**	**$909**	**$716**	**$790**	**$876**
Guidance			*935-1,085*	*885 (840 Post TSA)*			
UBS Prior		*915*	*992*	*924*	*713*	*798*	*885*
Consensus			*985*	*906*	*742*	*768*	

Source: Company Filings, ThomsonReuters, FactSet, and UBS Estimates

Valuation: Maintain $18 Price Target

Our valuation methodology is unchanged and we still utilize a 2017E sum-of-the-parts analysis. Items of note in our approach are (1) Inclusion of probability-weighted capacity performance; (2) Also probability-weighted potential to execute an accretive M&A deal; and (3) Normalization for Crane & Wagner beyond 2020. **Further details on our approach are available in our recent initiation here [page 19]**.

Figure 174: Updated Talen Energy Sum-of-the-Parts Valuation

Talen Energy - 2017E	UBS	EV/EBITDA Multiples					
	EBITDA	Low	Base	High	Low	Base	High
PPL Supply	349	7.0x	8.0x	9.0x	$2,446	$2,796	$3,145
RJS (Riverstone)	151	7.0x	8.0x	9.0x	$1,060	$1,211	$1,363
Less: Crane & Wagner 2	(26)	7.0x	8.0x	9.0x	($183)	($209)	($235)
Synergies	183	7.0x	8.0x	9.0x	$1,280	$1,463	$1,646
Capacity Performance Uplift	79	0.0x	3.0x	5.0x	$0	$236	$393
M&T (EnergyPlus)	32	4.0x	5.0x	6.0x	$128	$160	$192
Total Unregulated EV	**768**	**6.2x**	**8.0x**	**8.5x**	**$4,731**	**$5,656**	**$6,503**
Net Debt							
PPL Supply					$2,848	$2,799	$2,798
RJS					$1,190	$1,165	$1,147
Plus: Crane & Wagner 2 FCF NPV					($106)	($106)	($106)
Cash and 2015/2016 FCF					($474)	($458)	($455)
Total Net Debt					**$3,457**	**$3,401**	**$3,384**
Net Debt / Adj. EBITDA					*5.0x*	*4.3x*	*4.3x*
Total Equity Value					**$1,274**	**$2,255**	**$3,118**
Implied FCF Yield (EBITDA - Capex - Interest Exp - Taxes)					14%	8%	6%
Shares Outstanding					128.5	132.8	134.9
Standalone Talen (TLN) Valuation					**$9.91**	**$16.98**	**$23.12**
Accretive M&A Potential [50% Base Probability]		**0%**	**50%**	**100%**	**$0.00**	**$1.45**	**$2.90**
Talen (TLN) Price Target					**$10.00**	**$18.00**	**$26.00**
Upside/(Downside)					**-42%**	**4%**	**51%**

Source: Company Filings and UBS Estimates

TECO Energy (Buy, $20 PT)

Quarterly looks weak due to timing items. Focus remains on the 1% (TECO Coal) when the real story is about the rate case stay-outs and above-average utility growth. Expect more discussion of gas ratebase opportunity later this year.

We forecast TECO Energy reporting adjusted 2Q15 EPS of **$0.25**, down YoY versus Consensus expecting flat EPS ($0.28). We estimate that the Florida utilities are up $0.02/sh YoY due largely to favorable weather trends but outside of Florida the company faces headwinds due to timing items for the most part. New Mexico Gas Company is expected to post a small loss in the shoulder month (positive earnings are concentrated in 1Q/4Q) and TECO Coal generated income that will not be present in 2Q15 when classified as discontinued. The unusual 'wildcard' this quarter driving the YoY decline is parent where services cost, unallocated interest and Additional Short-Term Incentive (ASTI) compensation expense lead to unusually large and unfavorable comparisons given the recognition method's timing. Although the compensation expense is a large driver for the quarter, this is fully reflected in guidance and our FY15 estimates. Finally dilution trims another -$0.02 from our estimate.

Negative comparisons at TECO Coal, NMGC, and Parent/Other more than outweigh the positives at Florida and are expected to drive an earnings miss.

Figure 175: TE 2Q15 Earnings Walk

2Q15 Earnings Walk	EPS	*Additional Commentary*
2Q14A Adjusted EPS	**$0.28**	
Florida Utilities		
Return to Normal Weather	$0.01	*4% unfavorable Degree Days in 2Q14*
Impact of Weather	$0.01	*Favorable weather patterns*
Tampa Electric Rate Increase	$0.01	*~$7.5Mn rate increase effective 11/1/14*
Sales/Ratebase Growth at Elec./Gas	$0.01	*$300M-$350M capex minus $100M depreciation*
D&A	($0.00)	*Normal increase in depreciation*
O&M	($0.01)	*Expectation for flat to slightly favorable trend*
Interest Expense	$0.00	*Increase from NMGC acquisition offset by Parent Refinance*
TECO Coal Reversal	($0.00)	*+$0.8Mn in 2Q14; Removed from Operating EPS in 2015*
New Mexico Gas Co. (NMGC)	($0.01)	*Negative contribution in 2Q/3Q*
Parent & Other (ATSI)	($0.02)	
Dilution	($0.02)	*16.7Mn shares issued around July 8th, 2015*
1Q15E Adjusted EPS	**$0.25**	
Consensus	***$0.28***	
2015 Guidance	*$1.08-$1.11*	
2015 UBSe	*$1.09*	
2015 Consensus	*$1.10*	

Source: Company Filings, FactSet, and UBS Estimates

For more detail on these issues, please see our other recent reports:

4/29/15 Tapping the Tampa Treasure
2/10/15: Tampa Thunder: Upgrade to Buy
2/9/15 Feeling The Weight of Coal (First Read)

What's new with TE?

- **Back to the drawing board for Coal?:** TECO disclosed that it will be taking another write-down on its coal business which currently had $60Mn net book value. In June TECO announced that it had signed a non-binding letter of intent with a new potential purchaser of TECO Coal but that agreement has now expired. Neither the name of the new potential party nor the expected proceeds were disclosed by TECO. Importantly TECO stated that the new potential partner is not expected to need third-party financing like Cambrian does. The agreement with Cambrian Coal (owned by Booth Energy) has not yet been terminated but can be terminated by either TECO or Cambrian with a nominal penalty paid to TECO. The original Cambrian deal was originally announced in October 2014 and was subsequently amended down to $80Mn ($0.34/sh) of base proceeds.

Probability of a coal sale continues to weaken by the month as market outlook grows bleaker *but* this segment is immaterial to TECO.

Management has stressed that it has multiple interested parties and a deal with either the new unnamed party or Cambrian is not off the table. Based upon the disclosure that management intends to write-down the business below $60Mn, we would expect Cambrian and TECO to sign a new deal at a materially lower price than the last $80Mn agreement if the transaction is to continue. We understand that Cambrian is still attempting to secure financing and while the weakening coal market should reduce the purchase price, it simultaneously makes it more challenging to raise the necessary financing to support the deal.

Conversations with Cambrian and the unnamed party have not terminated.

While investors fear of late have migrated to concerned of a negative value, we see focus as remaining firmly around any deal to close out this business. *We continue to see a re-rating opportunity for shares, much the way the integrated utilities have divested their IPP assets of late in search of reduced volatility and higher regulated-only multiples.*

- **After NEE paved the way, TECO could introduce gas ratebasing plan later this year:** Now that the Florida PSC has approved NextEra's Florida Power & Light (FP&L) subsidiary's plan to invest in natural gas reserves, we expect to see TECO follow. The approved guidelines permit NEE to invest up to $500Mn per year subject to daily gas burn limits (5% of average daily burn in 2015 rising by 5% annually to 20% in 2018). The PSC will review the program's success after 3-5 years (2018-2020) at which point it could opt to increase or reduce the spending based upon how much customer savings are projected given the commodity environment at that point.

TE is interested in gas reserve investments but cautioned that any plan could take time to develop and would be at a smaller scale than NEE's plan.

TECO has confirmed that it has a team working to examine the merits of a similar plan for its subsidiaries but cautioned that it would take some time to prepare the necessary evidentiary support if and when it decides to go ahead (our understanding is that NEE had been preparing its application for quite some time). For a sense of scale, TECO's gas consumption needs are about 1/6th the size of FP&L, indicating that TECO could receive approval for ~$80Mn per year on a proportional basis. Since natural gas represents a smaller portion of TECO's generation mix, we would expect the Commission to permit a smaller program. For example, a $50Mn pilot program could generate EPS of $0.01/sh, or ironically equal to all of the value we ascribe to the Coal business today. We emphasize that this is where investors should be focusing.

- **Proactively avoiding rate case risk:** Investor attention continues to gravitate to the latest developments on the coal divestiture but in our view the real story investors should be focusing on relates to the Florida and New Mexico rate cases. When we met with management recently at the AGA Financial Conference they appeared confident in their ability to stay-out of rate cases in both jurisdictions. While the settlement precludes any rate hike prior to January 1st, 2018, the latest statements from management suggest it will continue to earn near its authorized ROE for the foreseeable future (seemingly through 2018 and 2019).

No rate cases in foreseeable future

Earnings estimates refined but still above Consensus

We have refined our estimates slightly but still remain above Consensus in 2017/2018E.

Figure 176: Updated TECO Estimates

TE Earnings by Segment	2014A	2015E	2016E	2017E	2018E	2019E
Regulated Florida Utilities	$1.17	$1.19	$1.25	$1.37	$1.43	$1.52
New Mexico Gas Co.	$0.03	$0.09	$0.10	$0.12	$0.15	$0.16
Parent	($0.16)	($0.19)	($0.18)	($0.19)	($0.19)	($0.19)
Total	**$1.03**	**$1.09**	**$1.17**	**$1.30**	**$1.39**	**$1.49**
Prior UBS Estimates	**$1.03**	**$1.10**	**$1.18**	**$1.32**	**$1.41**	**$1.51**
Consensus (7/6/15)	*$1.03*	*$1.10*	*$1.18*	*$1.28*	*$1.32*	
Guidance (4Q14 update)	*$1.00-$1.05*	*$1.08-$1.11*				
Dividends per Share	$0.88	$0.90	$0.92	$0.94	$0.96	$0.98
Dividend Payout Ratio (In %)	85.7%	82.6%	78.7%	72.3%	69.0%	65.9%
Quarterly DPS Increase Assumption		$0.005	$0.005	$0.005	$0.005	$0.005
Guidance Payout Target			*60-70% Target*			

Source: Company Filings, FactSet, and UBS Estimates

Valuation: Reduce Price Target $2 to $20

We continue to use a 2017E sum-of-the-parts methodology and the $2 reduction in valuation is driven primarily by a modest reduction in the peer multiple since our last update. Due to the latest Coal disclosures as discussed previously, we have reduced our valuation estimate by 50% for TECO Coal to $40Mn from $80Mn previously. **TECO Coal now is worth less than 1% of our Price Target.**

TECO is now trading at a discounted relative P/E when we believe it should be trading at a premium: after the coal divestiture is completed, this is an above-average growth rate regulated SMid utility with the potential for an acquisition, checking almost all of the boxes for ideal utility exposure in a rising interest rate environment (high parent leverage is a negative). A re-rating could begin in 2H after TECO eventually disposes of the Coal business or substantially writes it down to an immaterial value. Updates on capex opportunities including Florida gas ratebasing and LNG peak shaving in New Mexico could give more confidence in the growth trajectory. Further consolidation in the sector could also be a positive catalyst. The primary risk to our Buy relates to the company's relatively higher payout and div yield, at the higher end of the sector in a rising rate environment.

Figure 177: Updated TECO Valuation

TECO Valuation (UBSe)			Low Case		Base Case				High Case	
Business Segment	**Valuation Metric**	**2017**	**Valuation Multiple**	**($ MM) Value**	**Base Valuation Multiple**			**($ MM) Value**	**Valuation Multiple**	**($ MM) Value**
Regulated Entities										
					Peer Multiple	Prem. to Peer	Base Multiple			
Tampa Electric & Peoples Gas	P/E	$1.37	13.7x	$4,400	14.7x	0.5x	15.2x	$4,882	17.2x	$5,524
New Mexico Gas	P/E	$0.12	13.7x	$392	14.7x	0.5x	15.2x	$435	17.2x	$493
Regulated, Equity Value ($Mn)				**$4,793**				**$5,317**		**$6,017**
Regulated, Equity Value ($/sh)				**$20.38**				**$22.62**		**$25.59**
Unregulated and Parent Businesses										
Coal	Trans.	$40	N/A	$20	N/A	N/A	N/A	$40	N/A	$40
Parent & Other Drag	P/E	($0.19)	15.7x	($690)	14.7x	0.0x	14.7x	($646)	13.7x	($602)
Unregulated, Equity Drag ($Mn)				**($670)**				**($606)**		**($562)**
Unregulated, Equity Drag ($/Sh)				**($2.85)**				**($2.58)**		**($2.39)**
TECO Equity Value				**$4,123**				**$4,712**		**$5,455**
Fully Diluted Outstanding Shares (2017E)				235				235		235
TECO Equity Value per Share				**$18.00**				**$20.00**		**$23.00**
Implied Multiple: Consolidated UBSe 2017 EPS & UBS Price Target								**15.4x**		
Premium/(Discount) to Peers								**0.7x**		
Implied Multiple: Consensus 2017 EPS & Market Price								**15.0x**		
Premium/(Discount) to Peers								**0.3x**		

Source: Company Filings, FactSet, and UBS Estimates

AES Corp. (Neutral; $13 PT)

2Q Estimate – down YoY, expect a miss vs street consensus

We look for a disappointing quarter of **$0.22** vs consensus of ~$0.28, and also a 2Q14 of $0.28. The biggest YoY negative this quarter is our estimated -$0.04 attributable to reversals at Sul; and yet another quarter of fx/commodity headwind – we estimate MtM YoY change of -$0.02 this quarter. Asset sales continue to play a role in reducing earnings, as we factor in another quarter headwind of a penny each from lost earnings attributable to IPALCO, as well as AES' stake in the Philippines coal IPP, Masinloc. We also flag a partial offset from continued capital allocation efforts with additional share repurchases YoY.

Once again foreign currency and commodity headwinds dampen quarterly results driving a negative YoY result

Figure 178: 2QE YoY EPS

AES Earnings Walk	EPS
2Q14A Adjusted EPS	**$0.28**
Sul Reversal - Provision for some	(0.04)
Hydrology (more 2H15 impacted)	0.00
F/X & Commodities MtM	(0.02)
SG&A Savings (Continued Execution @ $5-10 Mn/qtr pa	0.00
Capital Allocation - Debt and Equity	0.02
IPALCO - Selldown	(0.01)
Philippines - 45% of stake	(0.01)
Tax Rate (31-32%)	0.00
2Q15E Adjusted EPS UBSe	**$0.22**
2Q15E Consensus	***$0.28***
2015 UBSe	***1.27***
2015 Guidance	***1.25-1.35***
2015 UBSe	***1.27***

Source: Thomson Reuters and UBS estimates

For additional context, please refer links to relevant recent reports below:

4/2/15 Streamlining the Story
2/26/15 Dry Spell
1/21/15 Another Guidance Cut Ahead?

Critical Issues

- **AES Tiete: Restructuring and Asset Divestments from**

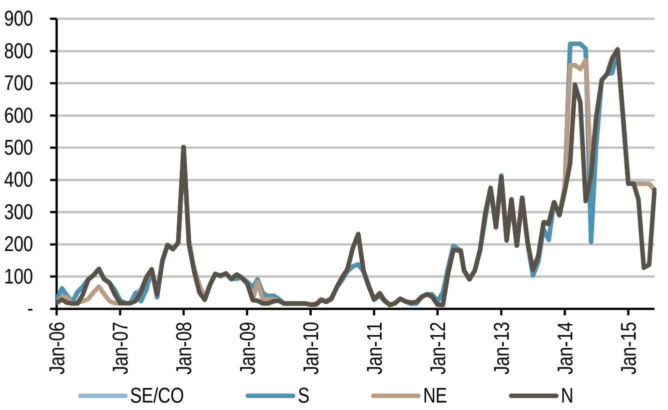
Following a (long-awaited) corporate restructuring with BNDES, AES Tiete is poised to effectively 'spin out' from AES Brazil (full note). This is the clearest positive development for AES YTD, shaking off restrictions from BNDES, and enabling the company to effectively re-lever its balance sheet by $500 Mn (equating to a total potential ~$1 Bn in deployable capital). Deploying this at a 6x multiple, we see this adding ~$167 Mn/yr in EBITDA—or roughly $0.04. The segment had been historically under-levered waiting for action from BNDES as well as we opportunity to deploy. We see the move by BNDES as not a coincidence following indications that Petrobras would seek to divest 6GW of thermal generation assets in order to delever following latest oil price slide; a firm timeline has yet to be released. While renewable additions are less desirable strategically, we still see a combination with Duke as having good logic potential SG&A synergy potential btwn 2 hydro portfolios—and as exit for Duke too. We look for further details on a June 12th conference call with AES Tiete management.

- **PPAs for DPL? Putting its hand out in Ohio too potentially.** AES' DPL plants remain profitable under current capacity rules (except for OVEC) and the company currently embeds $40M-$60M of upside in guidance from higher capacity payments under PJM's Capacity Performance (CP) proposal. In light of yesterday's announcements regarding FERC's postponement of a decision on CP, management indicated that it would consider following the lead of FE and AEP in filing for PPA revenues should higher capacity payments fail to materialize.
- **AES-DYN readthrough on synergies?:** Synergies on the Midwest coal portfolio. Following DYN's latest comments to revise up synergies on its latest acquisition, we suspect some of these benefits will accrue to AES as well. We caution that management had contemplated some upside already at DPL relating to capacity performance.
- **Tiete: GSF upside on contracting?** Pls see our associated report

Hydrology Update

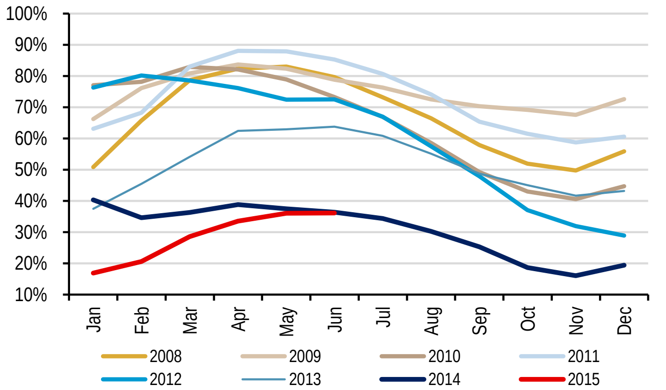
AES is most concerned about hydrology risks in Brazil; management does not appear concerned about Chile and Columbia, where hydrology levels are similar to those in historical years. On the 1Q15 earnings call, AES estimated non-GAAP EPS impact of $0.07 per share for FY15 from poor hydrology conditions in Brazil.

Figure 179: Brazilian Spot Power Prices ($Rs/MWh)



Source: ONS

Figure 180: Brazilian Hydrology – Reservoir Levels for Southeast



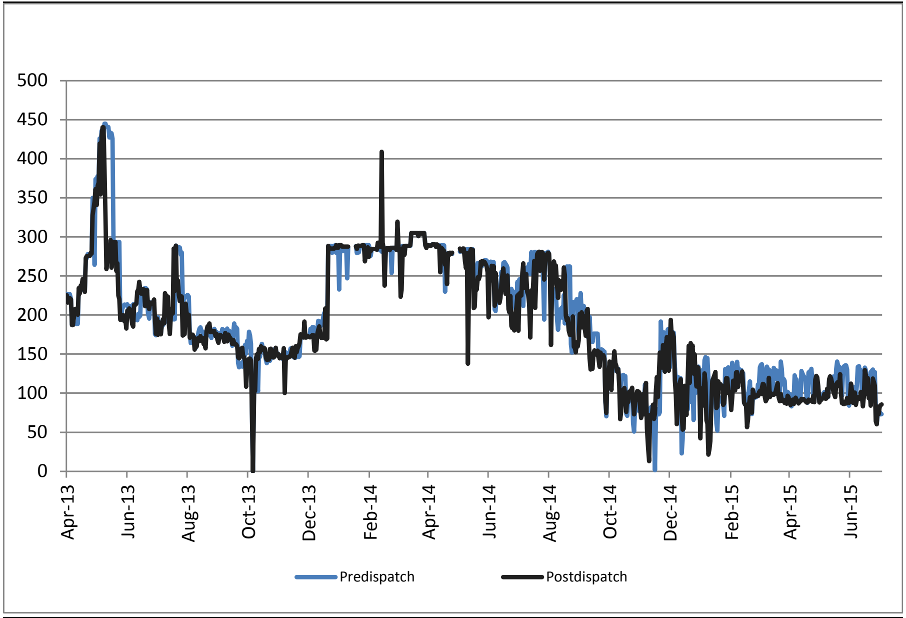
Source: ONS

Panamanian Hydro Disclosures

Following significant scrutiny in 2013 of hydro levels across Central America, we include recent spot prices following the significant drought conditions experienced recently.

Hydrology in Panama has also improved significantly following a severe drought in 2013 similar to others in South America. On its 1Q15 call AES Management mentioned about improved inflows close to long-term average) and normal hydro conditions in 2015. We note spot prices were down to $100/MWh

Figure 181: Panama Spot Prices- Pre/Post-Dispatch (Generation MWh per Unit System) – Slightly off the recent highs



Source: Company Reports

F/X headwinds still negative YoY, but stabilize QoQ

We compare the latest movement in F/X and commodity prices with that of the guidance provided by AES based on currency and commodity forward curves and forecasts dated March 31, 2015. We note except Columbian Peso, all other currencies posted some amount of gains against USD since the last guidance issued. Simultaneously, crude and power prices recovered against the drop in NYMEX Coal, Henry Hub and NBP prices (Please see the table below). We suspect shares have already found their lows for 2015, and our calculation suggests this could potentially add $0.03 to the guidance issued by AES.

That said, the trend in F/X is still similar and USD gains almost all of AES' operating currencies on Y-o-Y basis (Please refer the table on Y-o-Y comparison below). Similarly, all of the commodities were down on both YTD and Y-o-Y basis.

F/X Rate Fluctuations

We include charts of currency affecting AES. The next table showcases the YoY percentage changes in the foreign exchange rates. Across all major regions with exposure for AES, we continue to see material YoY appreciation of the USD.

Figure 182: Change in F/X rate (Y-o-Y)

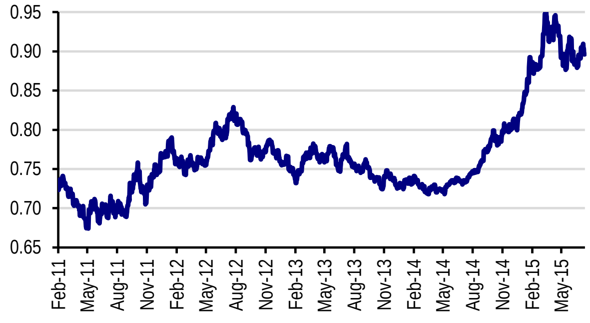
YoY % changes								
USD/ EURO	USD/Brazilian Real	USD/Chilean Peso	USD/Argentinean Peso	USD/ Mexican Peso	USD/ Peruvian Sol	USD/ British Pound	USD/Kazakhstan Tenge	USD/ Columbian Peso
22.0%	42.3%	17.0%	12.1%	14.2%	21.1%	10.3%	1.6%	44.0%

Source: Factset

Figure 183: F/X Rate for USD / Brazilian Real

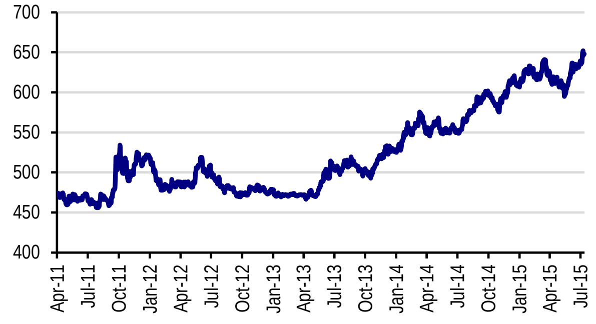
Source: FactSet

Figure 184: F/X Rate for USD / Euro



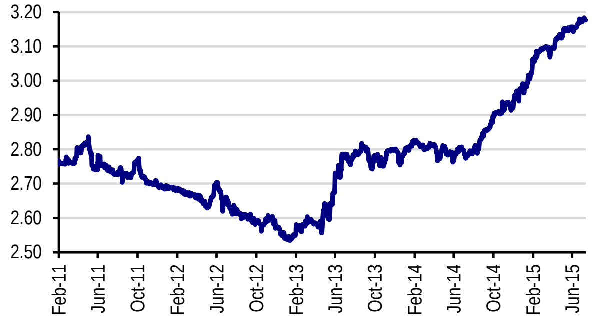
Source: FactSet

Figure 185: US Dollar per Chilean Peso



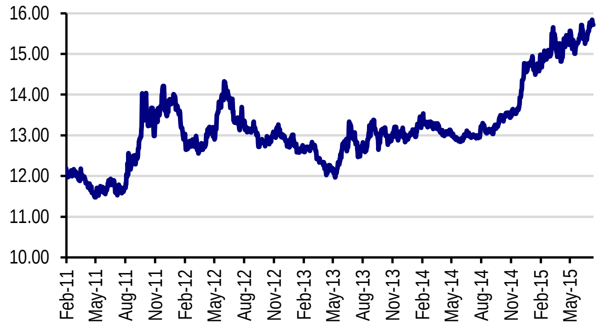
Source: Factset

Figure 186: US Dollar per Peruvian New Sol



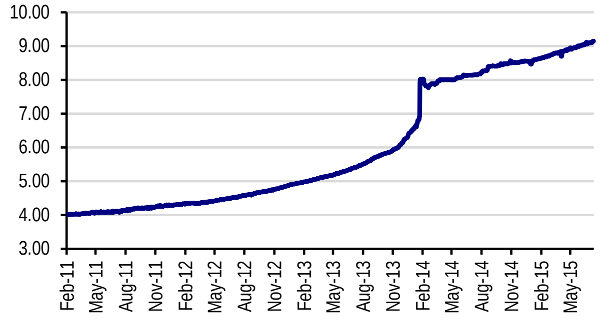
Source: Factset

Figure 187: US Dollar per Mexican Peso



Source: Factset

Figure 188: F/X Rate for USD / Argentine Peso



Source: Factset

Figure 189: Change in Commodities (Y-o-Y)

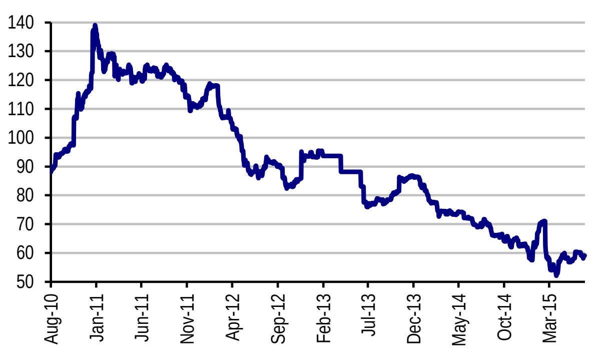
	CAPP	Newcastle	Henry	Brent	Crude	Rotterdam Coal
YTD	(19.0%)	(4.4%)	(3.7%)	0.8%	(2.7%)	9.9%
YoY	(31.5%)	(15.1%)	(32.5%)	(46.1%)	(48.6%)	(41.9%)
Min	41.03	52.05	2.51	47.82	43.46	55.90
Average	48.54	60.24	2.87	59.96	54.15	54.15

Source: Factset

Underlying International Commodity Performance

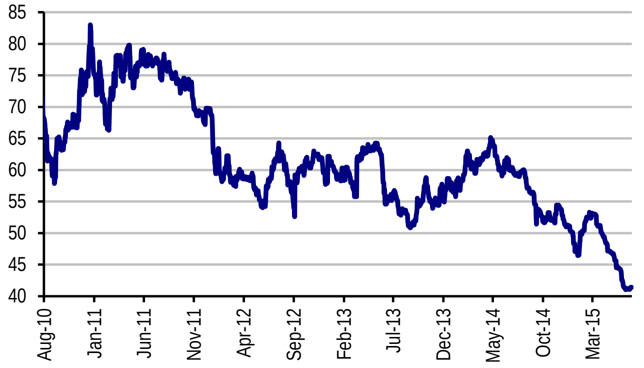
International coal prices have been declining since the beginning of the year and domestic coal prices after having a decent upward run for most part of the year, now hovering around $60 despite continued decline in International thermal coal.

Figure 190: Newcastle Coal ($/ton), International Coal Proxy



Source: FactSet

Figure 191: NYMEX CAPP Coal ($/ton), Domestic Coal Proxy

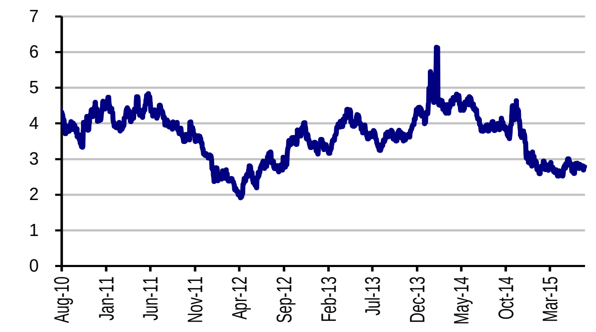


Source: FactSet

Comparing the Forward Gas Months: US vs. Europe

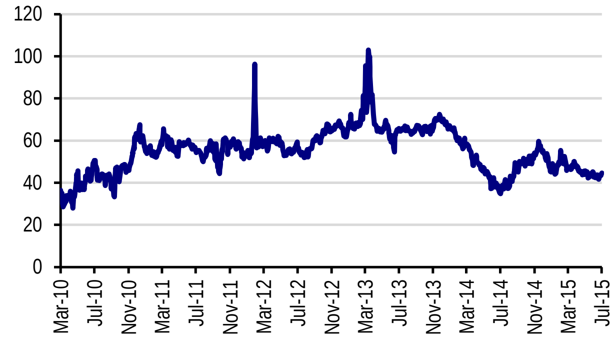
Henry Hub natural gas rose from August '13 lows of ~$3.23/MMBtu to a high of ~$6.15 on February 19th. They have been declining steadily since then and traded around ~$2.79 for the week ending July 10th. Meanwhile, European gas prices have experienced decline of -8.3% YTD, nut up 28% Y-o-Y basis. since the beginning of 2014 due to a warmer-than-normal winter. We see reversal of coal to gas switching at prices *at or above* $4.50/MMBtu as meaningfully capping upside to gas demand over the intermediate term.

Figure 192: US Natural Gas (Hub), $/MMBtu Front Month



Source: FactSet; 4Q11 Guidance (2012) = $3.2/MMBtu

Figure 193: European Natural Gas (NBP), pence/therm

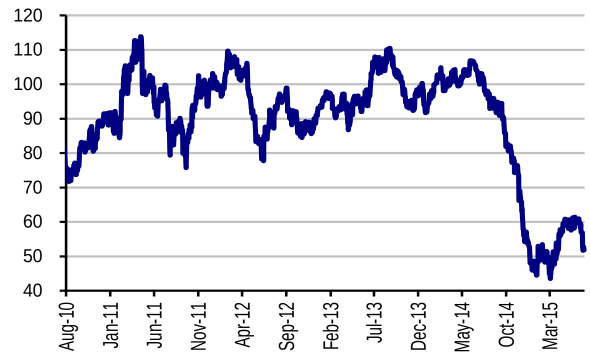


Source: Bloomberg; 4Q11 Guidance (2012) = £0.57/therm

Oil Prices: US vs. Europe

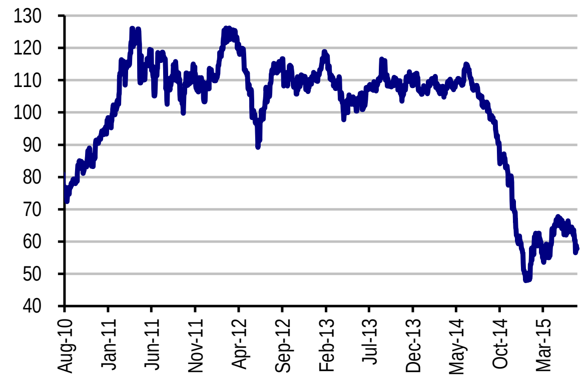
Meanwhile, domestic and international oil both continues to decline. YoY, Brent prices have fallen ~46% to ~$57.77/Bbl, while Crude WTI prices have decreased by ~49% to ~$51.82/Bbl.

Figure 194: Crude Oil (WTI), $/Bbl



Source: FactSet

Figure 195: Crude Oil (IPE Brent), $/Bbl



Source: FactSet

Comparison

Figure 196: Comparing the latest moves against 2015 guidance

FX Exposure	Argentine Peso	Brazilian Real	Euro	British Pound	Kazakhstan Tenge	Colombian Peso	
Average Rate assumed for 2015 as on 3/31/2015	9.69	3.32	0.93	0.68	210.30	2637.00	
Rate as on 7/10/2015	9.14	3.16	0.90	0.64	186.55	2673.83	
% change	-5.7%	-4.8%	-3.2%	-4.6%	-11.3%	1.4%	
Correlation	-ve	-ve	-ve	-ve	-ve	-ve	
Assumed sensitivity	0.005	0.005	0.005	0.005	0.005	0.005	
2015 EPS impact	0.0028	0.0024	0.0016	0.0023	0.0056	-0.0007	
2015 EPS Sensitivity	0.22%	0.18%	0.12%	0.18%	0.43%	-0.05%	
Commodity Exposure	NYMEX Coal	Rotterdam Coal	WTI Crude	Brent Crude	Henry Hub Nat Gas	UK NBP Nat Gas	PJM AD Hub
Average Rate assumed for 2015 as on 5/11/2015	50	58	51	58	2.80	47	33
Rate as on 7/10/2015	41.4	58.55	52.74	58.73	2.77	44.65	36
% change	-17.2%	0.9%	3.4%	1.3%	-1.1%	-5.0%	9.1%
Weighting	52%	48%	25%	75%	75%	25%	
Correlation		-ve		+ve		+ve	+ve
Assumed sensitivity	0.010	0.010	0.005	0.005	0.005	0.005	0.01
2015 EPS impact		0.0085		0.0009		-0.0010	0.0091
2015 EPS Sensitivity		0.65%		0.07%		-0.08%	0.70%
Total MtM Impact to EPS		MtM currency impact	MtM commodity impact	Total New Impact (EPS)	Total New Impact ($ Mn's)	% Change in EPS	
2015 EPS UBSe		0.0141	0.0175	0.03	34	2.4%	

Source: Company reports, FactSet, and UBS estimates

With 2015 EPS guidance perceived as 'safe', we suspect the focus will shift both towards how 2016 will trend (for instance, mgmt has already confirmed that the much awaited Tiete contract will now have a negligle impact as it rolls off YoY).

Further, the story appears to be one of opportunity around execution of the AES Tiete restructuring as well as any protracted associated efforts to acquire the contemplated Petrobras thermal power plant divestments. This would make use of leverage capacity at the subsidiary level. Moreover, opportunities around the Generation Scaling Factor (GSF) would suggest further upside for Tiete.

Net-net, we think we're through the downturn, albeit with shares trading north of 10x P/E, and more importantly in-line with our regional SOP.

Can shares re-rate around the Global YieldCo focus?

Among the bigger questions we see for shares is whether AES can capitalize on renewed interest in contracted emerging markets. While AES clearly does not have global growth expectations that come close to that of TERP or any prospective TERP Global spin from SUNE, we see an opportunity to highlight it's own flavor of EM-oriented growth to investors. While we've historically seen AES as a cautionary tale for SUNE's latest global expansion, we see the multiple upside for AES as well worth some attention. Given management's focus on FCF growth in recent periods (contemplated at 10-15% off a low base), as well as focus on growing its Div per Share at a corresponding level bodes well for the comparison.

What about versus 3/31/2015 commodities?

Additionally, we have analyzed the quarterly movement in currencies and commodities (see the table below). We found both the currency and commodity sensitivities were neutral to the EPS on Q-o-Q basis.

In another way to view the quarterly shift, we estimate the basket of commodities and F/X has moved against AES to the tune of $0.06 since the start of the year. The largest negative moves remain the Brazilian Real and the Euro. Continued erosion in US Natural gas prices could also prove a modest negative as well.

Figure 197: Change in F/X and Commodities in the Quarter

FX Exposure	Argentine Peso	Brazilian Real	Euro	British Pound	Kazakhstan Tenge	Colombian Peso	
Rate as on 3/31/2015	8.82	3.19	0.93	0.67	185.81	2599.97	
Rate as on 6/30/2015	9.09	3.10	0.90	0.64	186.21	2605.05	
% change	3.1%	-2.9%	-3.6%	-5.6%	0.2%	0.2%	
Correlation	-ve	-ve	-ve	-ve	-ve	-ve	
Assumed sensitivity	0.005	0.005	0.005	0.005	0.005	0.005	
2015 EPS impact	-0.0016	0.0014	0.0018	0.0028	-0.0001	-0.0001	
2015 EPS Sensitivity	-0.12%	0.11%	0.14%	0.21%	-0.01%	-0.01%	

Commodity Exposure	Coal		Crude Oil		Nat Gas		US Power
	NYMEX Coal	Rotterdam Coal	WTI Crude	Brent Crude	Henry Hub Nat Gas	UK NBP Nat Gas	PJM AD Hub
Rate as on 3/31/2015	51.08	58.85	47.60	55.11	2.64	48.33	35.48
Rate as on 6/30/2015	41.10	59.30	59.47	63.59	2.83	42.14	35.50
% change	-19.5%	0.8%	24.9%	15.4%	7.3%	-12.8%	0.1%
Weighting	52%	48%	25%	75%	75%	25%	
Correlation	-ve		+ve		+ve		+ve
Assumed sensitivity	0.0100	0.0100	0.0050	0.0050	0.0050	0.0050	0.0100
2015 EPS impact		-0.0098		0.0089		0.0011	0.0001
2015 EPS Sensitivity		-0.75%		0.68%		0.09%	100.00%

Total MtM Impact to EPS		MtM currency impact	MtM commodity impact	Total New Impact (EPS)	Total New Impact ($ Mn's)	% Change in EPS	
2015 EPS UBSe		**0.0042**	**0.0003**	**0.00**	**5**	0.3%	

Source: Company reports, FactSet, and UBS estimates

Valuation: Latest SOP Update – Model Overhaul

We embed our latest Sum of the Parts valuation below

Since AES' last guidance based on currency and commodity forward curves and forecasts dated March 31, 2015 all currencies except Columbian Peso posted some amount of gains against USD. Existing negative correlation between USD and all other currencies, and AES' sensitivity guidance of $0.005 could possibly add $0.01 to the 2015 EPS guidance. Additionally, NYMEX coal prices were dropped by -17% since 5/11/2015, with PJM AD hub prices up by 9%, we believe, this could potentially add another $0.02 to the EPS. However, we are not assigning any value to it as we discussed earlier, these are comparison between the latest F/X rate and the last guidance issued by the AES management. As we mentioned earlier, all the commodities are down on Y-o-Y basis and all the currencies are down against USD on Y-o-Y basis.

Figure 198: Summary SOP View for AES Corp – Decrease to $13 PT from $14

Summary SOP Valuation for AES Corp	% Owned by AES				Low	Base	High
Listed Latin American Subsidiaries					$5.62	$5.62	$5.62
Latin American Utilities (Unlisted)					$1.09	$1.71	$2.10
Latin American Generation (Unlisted)					$2.57	$3.44	$4.31
North American Utilities					$1.61	$1.73	$1.85
DP&L Utility	100%				$2.78	$2.35	$2.67
DP&L Generation and Debt	100%				-$2.78	-$2.35	-$2.67
IPALCO	100%				$1.61	$1.73	$1.85
North American Generation					$2.67	$3.55	$4.31
Southland	100%				$0.64	$0.81	$0.98
Warrior Run	100%				$0.52	$0.62	$0.72
Deepwater	100%				$0.00	$0.00	$0.00
Red Oak	100%						
Ironwood	100%						
Shady Point	100%				$0.23	$0.26	$0.30
Hawaii	100%				$0.00	$0.20	$0.26
Beaver Valley	100%				$0.00	$0.00	$0.00
Puerto Rico	100%				$0.64	$0.85	$1.07
Merida	55%				$0.36	$0.42	$0.47
TEG/TEP	99%				$0.28	$0.39	$0.50
Asian Generation					$1.10	$1.27	$1.44
European Generation					$0.91	$1.47	$2.03
Summary SOP Valuation for AES Corp					Low	Base	High
Total Subsidiaries Equity Value					$15.56	$18.78	$21.65
Other Adjustments (Parent Debt, etc)							
Parent Adjusments, Debt, and Corp/Other						(3,973)	
Shares Outstanding						690	
Parent Debt Oustanding and Cost Drag per Share						($5.76)	
AES Corp Total Equity Value per Share					$9.80	$13.02	$15.89
Parent Adjustments, Debt, Etc							
	2016 EBITDA	EV/EBITDA Multiple					
Corp/"Other" businesses (EBITDA)	65	6.0x	7.0x	8.0x	$389	$454	$519
	2017 Net Income						
Equity Investments	12	7.0x	8.0x	9.0x	$82	$94	$106
NPV of NOLs						$197	
Other Non-Recourse Debt (Corp/Other)							
Other Wind Projects, Euro/African Utes, etc						($269)	
Recourse Debt *(using latest reported 10K numbers)*							
Unsecured Notes						($5,258)	
Less Current Maturities						$151	
Secured Debt / Term Loans						$0	
Total Recourse Debt						($5,107)	
Total Cash (incl. Subsidiaries), FY14						$1,539	
Exclude Subsidiary Cash, FY14						($1,032)	
Net Debt (FY14)						($4,600)	
Announced assets sales						$558	
Parent FCF (mid point of guidance)						$525	
Investment in Subsidiaries						-$350	
Shareholder Dividends						-$282	
Expected Share Buyback						-$300	
Incremental Cash Generation FY15 to FY16						$151	
Parent Adjusments, Debt, and Corp/Other						(3,973)	
Shares Outstanding						690	
Parent Debt Oustanding and Cost Drag						($5.76)	
AES Corp Total Equity Value per Share					$9.80	$13.02	$15.89

Source: Company Filings, FactSet, and UBS Estimates

Westar (Neutral; $36 PT)

Staff ROE recommendation came in at 9.25%, a bit lower than expected (in-line with GXP) but we still assume a ~9.5% resolution. A positive surprise looks unlikely this quarter with transmission refund and dilution

Quarter looks weak given unfavorable weather, dilution, and the transmission refund.

We forecast Westar reporting adjusted 2Q15 EPS of **$0.41**, flat YoY and $0.04 below Consensus ($0.45). Weather is a -$0.03 net negative for the quarter but that is more than offset by reduced O&M in the second quarter. 2Q14 had a Wolf Creek outage as well as above-average coal planned outage expenses that should serve as a benefit YoY. D&A and AFUDC each reduce our estimate by -$0.02 (AFUDC is weighted in 1H15 whereas depreciation is back-end loaded). As a reminder, management reduced its FY15 retail sales growth target to 100bp from 150bp due to a low margin oil-sensitive customer's reduced output. The refund liability for the reduced transmission ROE of ~$4Mn roughly offsets the higher rates under the TDC Transmission rider. Dilution also drags by a penny as management settled 9Mn shares previously sold forward shares in May. There was no COLI recorded in the comparable quarter and we continue to assume that the proceeds are ratable throughout the year. If COLI proceeds do not materialize in the quarter, the miss could be even wider.

Figure 199: WR 2Q15E Earnings Walk

2Q15 Earnings Walk	
2Q14A Adjusted EPS	**$0.41**
Weather vs Normal in 2Q14	($0.02)
Weather vs Normal in 2Q15	($0.01)
Energy Marketing in 2Q14	$0.00
Retail Sales Growth: 100 bps	$0.01
Transmission Rates (TDC)	$0.01
Environ. Cost Rider (ECRR)	$0.01
Transmission Refund	($0.01)
O&M	$0.04
D&A	($0.02)
AFUDC	($0.02)
Interest Expense	$0.00
Share Dilution	($0.01)
Eff. Tax Rate 32% to 33%-35%	($0.01)
COLI Proceeds	$0.03
2Q15E Adjusted EPS UBSe	**$0.41**
2Q15 Consensus	*$0.45*
2015E UBSe	*$2.26*
2015E Consensus	*$2.25*
2015 Guidance	*$2.18 - $2.33*

Source: Company Filings, FactSet, and UBS Estimates

For more detail on these issues, please see our other recent reports:

5/7/15 One ROE Revision Reflected, One To Go
5/6/15 Taking A Dose of Transmission Medicine
3/2/15 Entering the Bullring
10/2014 "Koncerned about Kansas"

What's new with WR?

- **Settling transmission ROE complaint at 10.3%:** Westar and the Kansas Corporation Commission (KCC) agreed to a settlement in its pending transmission ROE case with a 10.3% ROE and $10Mn refund. The 10.3% ROE is in-line with Westar's previous disclosures with 1Q15 and is based upon a 9.8% base ROE plus a 50bp adder for RTO participation. Following the KCC's settlement at 9.8% base, it remains to be seen how they will view Westar's 10% ROE request in the pending rate case discussed below.

Transmission ROE settlement in-line with expectations and previous disclosures.

Below we show our Westar ROE scenario analysis and we have already reflected the 10.3% ROE in our forward estimates.

Figure 200: Westar Transmission ROE Analysis – What's the future impact?

ROE Reduction Analysis					
~11.40% ROE	**2014A**	**2015E**	**2016E**	**2017E**	**2018E**
Ratebase ($Mn)	1,100	1,200	1,400	1,500	1,700
Approved ROE	11.40%	11.40%	11.40%	11.40%	11.40%
Assumed Equity Ratio	52.4%	52.6%	52.6%	52.6%	52.6%
Net Income	$66	$72	$84	$90	$102
~10.4% ROE	**2014A**	**2015E**	**2016E**	**2017E**	**2018E**
Ratebase ($Mn)	1,100	1,200	1,400	1,500	1,700
Approved ROE	10.4%	10.4%	10.4%	10.4%	10.4%
Assumed Equity Ratio	52.4%	52.6%	52.6%	52.6%	52.6%
Net Income	$60	$66	$77	$82	$93
Net Income Delta	-$6	-$6	-$7	-$8	-$9
EPS Impact	**-$0.04**	**-$0.04**	**-$0.05**	**-$0.05**	**-$0.06**

Source: Company Filings and UBS Estimates

- **Kansas rate case process to dominate summer for Westar – Staff proposes 9.25% ROE vs 10.0%:** Staff/Intervenor testimony was filed on July 9th and the most controversial issue appears to be ROE. Westar has requested an unchanged 10.0% ROE (53.34% equity ratio) and estimates $19Mn of rate savings for customers due to a ~100bp decline in the cost of debt since its last rate case despite the unchanged equity return percent. The Staff supported a 9.0%-9.5% ROE range (9.25% midpoint). The $152Mn request is driven primarily by plant upgrades at La Cygne ($68Mn - environmental) and Wolf Creek ($51Mn – life cycle extension), areas where we do not anticipate material pushback. The PSC Staff estimates that every 10bp of ROE is worth $4.4Mn revenue requirement.

What are the rate case dates to watch?
July 21st: Public Hearings
July 29th: Rebuttal Testimony
August 3rd-7th: Settlement Conference
August 17th-21st: Evidentiary Hearings
September: Briefs filed
October 28th: Decision Expected

Great Plains Energy (GXP) filed in January for a 10.3% ROE at its Kansas City Power & Lights (KCP&L) subsidiary; however, the KCC Staff recommended a 9.0-9.5% ROE (9.25% midpoint) on May 11th. With GXP's case leading Westar's by two months, this should be a prime source of read-throughs for Westar's case. **We continue to assume a 9.5% ROE for the upcoming rate case due to low recent comps: specifically the recent Staff proposal (9.25%), GXP case (9.25%) and Atmos Energy's (9.1%) in September.**

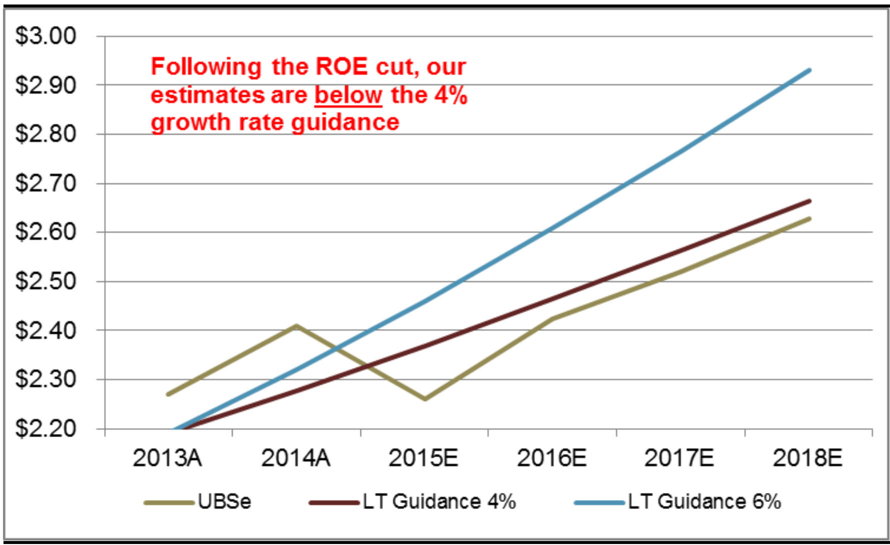
Westar has also requested a rider for grid resiliency spending as well as an adjustable ROE mechanism. The grid resiliency rider would work in a similar fashion to the mechanism in California (driven off the average yield of the Moody's utility Bond index) and allow more timely recovery of capital without requiring a full rate case to recovery the capital costs in rates, similar to the environmental cost recovery rider (ECRR).

Westar:	Docket 15-WSEE-115-RTS
Great Plains Energy:	Docket 15-KCPE-116-RTS

- **Growth continues to trail guidance but unlikely to update with case pending:** Based upon UBSe/Consensus EPS estimate of $2.63 in 2018E, Westar is trending below its 4-6% 2013-2018E CAGR. The below-average growth and uncertainty around the Kansas ratecase likely explain the ~0.7x P/E discounted valuation for shares today. Westar trades at 14.1x/13.6x on 2016/2017E versus peers at 14.8x/14.0x. Following resolution of the rate case in late October, look for management to address the EPS CAGR, potentially revising it down to 3-5% depending on the outcome of the rate case.

Based upon UBSe/Consensus estimates, Westar's EPS CAGR lags the 4-6% guidance.

Figure 201: Westar EPS Trajectory



Source: Company Filings, FactSet, and UBS Estimates

- **RPS no longer mandatory in Kansas:** In May the Kansas legislature passed and Governor Brownback (R) enacted a bill to replace the state's renewable portfolio standard (RPS) with a voluntary goal. The target was unchanged at 20% of peak demand coming from renewable sources by 2020 but is now not a requirement for the utilities to achieve. As of YE14 9% of Westar's capacity was renewables (669MW) and the plan is to achieve 16% in the near future. Although Westar does not have 20% of its capacity as renewables, the former RPS/current voluntary target is based on a percent of peak load and management anticipates (still) fully complying. Based upon its planned additions Westar anticipates surpassing the voluntary goal in all years. Westar has emphasized that it will continue to add renewables not just to meet the target, but because the pricing is attractive relative to its alternatives.

- **MATS spending mostly complete:** Westar has already spent 2/3rds of its MATS budget as Activated carbon injection (ACI) equipment installation is scheduled for mid-2015 and management did not slowdown any spending as a result of MATS uncertainty. The Supreme Court case could allow management to delay some of the remaining spending and ultimately drive O&M savings for customers depending on final resolution. Looking forward the majority of Westar's remaining spending is related to Carbon and 94% of its coal fleet is currently scrubbed. In 2015 there is ~$75Mn of

environmental capex scheduled and another ~$75Mn planned for 2016-2019E as Westar recently exited its peak spending years.

Estimates remain unchanged

Our estimates have not been revised as we previously adjusted for a lower base ROE assumption in the pending rate case and the transmission ROE complaint. With 1Q15 results we reduced our estimates by $0.08 in 2015 and ~$0.06 per year in 2016-2018. Our estimates are generally in-line with consensus throughout the investment horizon.

Figure 202: Westar EPS Estimates - Unchanged

Westar EPS Estimates	2013A	2014A	2015E	2016E	2017E	2018E
UBSe	$2.27	$2.41	$2.26	$2.42	$2.52	$2.63
Prior estimate	$2.27	$2.41	$2.26	$2.42	$2.52	$2.63
Consensus	*$2.27*	*$2.35*	*$2.25*	*$2.46*	*$2.51*	*$2.63*
Guidance		*$2.35 - $2.45*	*2.18 - $2.33*			
Authorized ROE (Implied)		10.00%	10.00%	9.50%	9.50%	9.50%
Regulatory lag & other		-0.92%	-1.77%	-0.26%	-0.31%	-0.28%
Earned Kansas Dist ROE		9.08%	8.23%	9.24%	9.19%	9.22%
Long-term 5-Yr CAGR 4%-6% off adjusted 2013 base						
LT Guidance 4%	$2.19	$2.28	$2.37	$2.46	$2.56	$2.66
LT Guidance 5%	$2.19	$2.30	$2.41	$2.54	$2.66	$2.80
LT Guidance 6%	$2.19	$2.32	$2.46	$2.61	$2.76	$2.93

Source: Company Filings, FactSet, and UBS Estimates

Valuation: Reduce Price Target $2 to $36

We have reduced our 2017E sum-of-the-parts derived Price Target to $36 due to 0.7x contraction in the regulated group peer multiple.

Figure 203: Updated Westar Energy Valuation

Westar Sum of the Parts Valuation - 2017E UBSe									
All US $Mn except per share data	EPS	P/E Multiple					Equity Value		
		Low	Peer Multiple	Prem /Disc	Base	High	Low	Base	High
Distribution	$1.86	12.5x	14.0x	0.0x	14.0x	15.0x	$3,314	$3,711	$3,977
Transmission	$0.56	13.0x	14.0x	1.0x	15.0x	16.0x	$1,032	$1,190	$1,270
COLI	$0.11	12.5x	14.0x	0.0x	14.0x	15.0x	$188	$210	$225
Total / Implied Utilities	$2.52	12.6x			14.2x	15.2x	$4,533	$5,112	$5,471
2017E Number of Shares Outstanding (Mn)							142.6	142.6	142.6
Equity Value per Share							$32.00	$36.00	$38.00

Source: Company Filings, FactSet, and UBS Estimates

WEC Energy Group (Neutral; $48 PT)

We expect to see an **in-line quarter at $0.56** vs consensus $0.56 and at the upper end of management guidance of $0.54-0.56. Compared to the last 2Q, key factors include +$0.01 for a return to normal weather, but adjusting a -$0.02 for unfavorably mild weather in April and June this year (May was average). We have factored in a+$0.02 vs 2Q14 for WEPCO rate change; and another penny increase from Wisconsin Gas rate change. Mgmt. told us that although FY O&M is expected flat, system optimization lead to higher maintenance this year – we factor in -$0.04 cents from higher O&M this quarter. The detailed changes we expect for 2Q15 vs 2Q14 are shown below:

Quarter appears to be at the upper end of guidance and in-line with Street. The big event this quarter was closure of the TEG deal.

Figure 204: 2Q15E Earnings Walk

2Q15 Earnings Walk	EPS
2Q14A Adjusted EPS	$0.58
Return to Normal Weather from 2Q14	$0.01
Weather in 2Q15	($0.02)
Normalized Grant Income for Biomass	($0.01)
Wepco rate change (Higher Elec/Lower Gas)	$0.02
Wisc Gas rate change	$0.01
O&M	($0.04)
ATC Transmission YoY	$0.00
PTF	$0.00
Benefit cost declines	$0.01
Interest Expense	$0.00
D&A	($0.01)
Parent	$0.00
2Q15E Adjusted EPS	**$0.56**
2Q15 Consensus	***0.56***
2Q15 Guidance (excluding costs-to-achieve)	***$0.54-$0.56***
2015 Guidance (excluding costs-to-achieve)	***$2.67-$2.77***

Source: Company Filings, FactSet and UBS Estimates

For additional context, please refer links to relevant recent reports below:

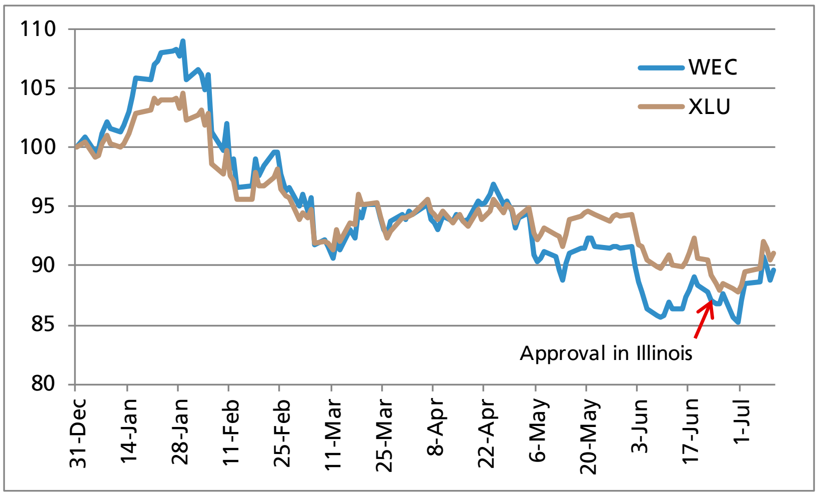
5/6/15 Running Towards the Finish Line
4/13/15 Clearing the Air Around Deal Accretion
2/12/15 Let's Make a Deal
10/31/14 Resolving the 'Presque Isle' Debacle
6/26/14 TEG-Tie: Upgrade to Neutral on Deal Accretion and Improved Growth Outlook

What's New With WEC over 2Q?

Merger with Integrys clears the last hurdle

WEC received its last required approval from Illinois regulators for its proposed acquisition of Integrys on 6/24 and we now expect the merger to officially close before the end of the month. As we noted previously in "Running Towards the Finish Line", we continue to think the Street has not yet fully baked in deal accretion and see ambiguity in formal forward EPS estimates as providing an opportunity for shares to trade higher into deal close. We show below stock price performance YTD – the stock rallied immediately after the announcement albeit corrected more recently.

Figure 205: WEC and XLU performance YTD



Source: Factset

Management intends to earn it's ROEs at the Integrys utilities in 2016.

We understand management will likely elaborate to a certain extent, but avoid any specific or direct reference to synergies arising from the deal. However, don't look for a change to management's long-term guidance of 5-7% off the midpoint of 2015 stand-alone EPS of $2.72. *We look to clarify on the 2Q whether the 5-7% EPS growth rate is consistent with earning it's allowed ROEs across all of its utilities in the first year; we suspect management may initially exceed this range, providing latitude in achieving this higher target (vs. 4-6% previously) in subsequent years.*

No synergy details at all still.

That said, management has provided few details of pro-forma benefits ahead of regulatory approval other than accretion in 2016 (the first full year of operations). Guidance for 2015 remains entirely standalone without upside on deal close and pro-forma 2015 guidance isn't expected until after the deal close. We see upwards of another ~$0.15 of possible upside from synergies that we assume (fully ramped up to ~3%non-fuel O&M); management has merely said that the deal is not dependent on synergies.

Approval in spite of lingering People's Gas issues

The approval comes despite an attempt by state Attorney General Lisa Madigan to tie approval to the pending outcome of a separate Illinois Commerce Commission (ICC) investigation into alleged mismanagement of People's gas main replacement program (any potential unrecoverable fines will now be paid by WEC). Concessions to the state were in-line with expectations and include a 2-year base rate freeze for both Peoples Gas and North Shore Gas and a $1B+ investment commitment for 2015-2017 for the two Illinois gas utilities. Additionally no transaction costs or acquisition premiums will be recovered in rates. Decoupling, the purchased gas adjustment clause, and most importantly, the gas main replacement riders will remain in place.

- **Amended March deal still the latest on Presque Isle**

Recall that WEC, TEG, and Michigan Governor Rick Snyder announced earlier this year a deal with Cliffs Natural Resources (CLF) that would solve the problem created in 2013 when Cliffs switched power suppliers away from WE Energies' Presque Isle plant to TEG's competitive trading subsidiary. The shift rendered the coal-fired plant uneconomic, with MISO nearly doubling the bills of Michigan Upper Peninsula residential customers for nearly $100M/year in system support payments (about half for emissions-reducing dry sorbent injection) in order to keep the plant open for reliability.

With UPPCO and Cliffs unable to reach an agreement on a new tariff, the deal was amended significantly in mid-March, with WEC keeping both Presque Isle and the Upper Peninsula distribution assets indefinitely. The iron ore mines have entered into long term contracts to purchase power from Wisconsin Electric. Cliffs will continue to be served by Wepco under a regulated tariff and Wepco will continue to have this small portion of its ratebase under Michigan jurisdiction. Mgmt. also said that WEC may potentially create a separate Michigan only utility to serve consumers in the Upper Peninsula in Michigan.

WEC will consider the option to build the replacement within ratebase as well, which could prove to be a source of material future growth.

Expect accretion starting in 2016

As illustrated in the table below, our 2015 pro-forma estimate is largely unchanged vs our formal standalone estimate, impacted by the seasonal timing of revenues for a mid-year closing date as well as a few cents of 1x cost-to-achieve. We do not believe management will elect to change 2015 guidance for the merger. However, starting in 2016 we expect to see about ~$0.10 of financial leverage accretion from P/E and cost of capital alone, boosted by the ramping up of HoldCo and other synergies at about $0.05 for every 1% of combined O&M (management has made no comment on synergies other than to say the deal is not dependent on them). *We see shares as trading 4% and 3% expensive to the peer group off 2017 and 2018, respectively.*

Figure 206: EPS Estimates – The key question is how to think about 5-7% growth? We're at midpoint in LT still.

	2014A	2015E	2016E	2017E	2018E	2019E	2020E	CAGR '15-'19
UBSe Standalone	$2.65	$2.75	$2.87	$3.00	$3.10	$3.17	$3.28	3.92%
UBSe (Prior)	*$2.65*	*$2.75*	*$2.87*	*$3.00*	*$3.10*	*$3.17*		
UBSe pro-forma for WEC-TEG		$2.72	$2.97	$3.13	$3.34	$3.48	$3.68	6.37%
Embedded synergies assumption % of O&M (UBSe)		-0.5%	0.5%	1.0%	1.5%	2.0%	3.0%	
Embedded synergies assumption (UBSe)		-$0.02	$0.02	$0.05	$0.08	$0.11	$0.16	
Consensus		*$2.72*	*$2.86*	*$3.02*	*$3.21*			
EPS Guidance		**$2.67-$2.77**		**5-7% EPS Growth**				
Implied EPS Guidance - Low			*$2.86*	*$3.00*	*$3.15*	*$3.31*	*$3.47*	
Implied EPS Guidance - High			$2.91	$3.11	$3.33	$3.57	$3.81	
Implied EPS Guidance - Mipdoint			*$2.88*	*$3.06*	*$3.24*	*$3.43*	*$3.64*	
Dividend	*$1.56*	*$1.79*	*$1.94*	*$2.00*	*$2.06*	*$2.12*	*$2.18*	
Dividend Growth		*14.6%*	*8.4%*	*3.0%*	*3.0%*	*3.0%*	*3.0%*	
Payout Ratio	*59%*	*65%*	*67%*	*67%*	*66%*	*67%*	*66%*	
Dividend Guidance	**14%-15% growth in 2015 and 65%-70% payout in 2017**							

Source: Company Filings, FactSet and UBS Estimates

Valuation: Lower PT $1 to $48 based on peer group multiple revision

Our valuation is based on 2017E P/E with relatively modest merger synergies assumption (management makes no assumption for synergies at this time). Our upside/downside skews more towards the negative but we caution that disclosures about O&M savings targets and pro-forma guidance expected with the deal closing could drive upside to numbers given a historically conservative management. *We see any share price outperformance as more driven by positive EPS revisions rather than any multiple re-rating.*

Figure 207: Updated WEC Energy Group Valuation

Wisconsin Energy Corp. Valuation: P/E Derived on 2017 EPS					
Downside Case		***Base Case***		***Upside Case***	
Valuation		**Price Target**		**Valuation**	
2017 EPS	3.00	2017 EPS	3.00	2017 EPS	3.00
P/E Multiple	14.0x	P/E Multiple	14.7x	P/E Multiple	15.5x
Premium	0%	Premium	5%	Premium	10%
Value	**$42.00**	**Value**	**$46.30**	**Value**	**$51.15**
**Base Case Price Target Rounded*					
Integrys Deal Accretion					
2017 EPS Accretion - UBSe	0.13	Accretion	0.13	Accretion	0.13
P/E Multiple	14.0x	P/E Multiple	14.7x	P/E Multiple	15.5x
Discount	-10%	Discount	-5%	Premium	0%
Value	**$1.70**	**Value**	**$1.88**	**Value**	**$2.09**
Valuation	**$44.00**		**$48.00**		**$53.00**
Upside/(Downside)	**-8%**		**0%**		**10%**

Implied Multiple: UBSe 2017 EPS & UBS Price Target	**15.3x**
Premium/(Discount) to Peers	**0.6x**
Implied Multiple: Consensus 2017 EPS & Market Price	**15.9x**
Premium/(Discount) to Peers	**1.2x**

Source: Company Filings, FactSet and UBS Estimates

Xcel Energy (Neutral; PT $35)

Small miss on 1x quarter with a small pickup from Minnesota rate trueup.

We expect XEL to report 2Q15 in-line at $0.39 vs consensus $0.41, with mostly normal weather. Rate increases across its various jurisdictions help $0.04, and the capital rider in Colorado helps $0.04 for the quarter as well, although this is offset by higher depreciation (-$0.05), O&M, interest expense, and property taxes. In Minnesota, the company received a final $165M rate increase on May 8 (with -$81M of depreciation offset already embedded in guidance and reflected at the bottom of our table below) vs the $102M level reserved for last year. However, on July 9th, the PSC amended that to $149.4M on reconsideration of revenue for Monticello before the EPU ascension process to full uprate condition was received from the NRC (expected in 3Q15). On July 13, XEL reiterated its previous guidance for 2015 of $2.00-$2.15 vs UBSe and consensus $2.09. We expect XEL to file another multi-year ratecase in Minnesota in 2016.

Figure 208: XEL 2Q15E vs 2Q14A Walk

XEL 2Q15 Earnings Walk	EPS
2Q14 EPS	$0.39
Weather Normal	$0.00
Milder than Normal Weather	$0.00
Sales Guidance (+1.0% elec, +0%-1% gas)	$0.01
Rate Cases	$0.03
Minnesota $149.4M (Jan 2015)	$0.02
ND Step Increase 9.4M (May 2014)	$0.00
ND Step Increase 10.25M (Jan 2015)	$0.00
SD $15.6M interim rates (Jan 2015)	$0.00
WI, electric (14.2M effective Jan 2015)	$0.00
CO-electric (-$39.4M 3-yr plan base decrease effective Feb 13 20:	($0.01)
TX - Oct 2014 $37M	$0.01
Capital Rider Revenue ($155-165M increase)	$0.04
Transmission revenue, net of costs	$0.01
Conservation and DSM program revenues (offset by expenses)	$0.00
NSP-Wisconsin fuel recovery	$0.00
Increased taxes (to normal 34%-36%)	($0.00)
Interest Expense (40-50 increase, 2H loaded)	($0.01)
O&M (0-2% growth in 2015)	($0.01)
AFUDC (30-40 decline)	($0.01)
Property Taxes (60-70 increase)	($0.02)
Depreciation (130-150 increase)	($0.04)
Dilution	($0.00)
2Q15 EPS	$0.39
2Q15 Consensus	*$0.41*
2015 Earnings Guidance	*$2.00-$2.15*
2015 UBSe	*$2.09*
2015 Consensus	*$2.09*

Source: Company Filings and UBS Estimates

For more detail on these issues, please see our other recent reports:

5/4/15 Fighting Off a Case of the Lag
4/6 In Search of Reform
1/30 Rocky Mountain Higher
11/3 Poised for Further Inflection?

- **Minnesota Energy bill signed into law.** With the bill signed into law on June 13, we estimate that its provisions will improve XEL's overall regulatory lag by roughly 30 bps as a result of longer plans (5 years), more formulaic rider mechanisms, recovery of O&M based on a price index, the implementation of interim rates during ratecases, the use of the nuclear depreciation surplus to smooth out revenue fluctuations and mitigate increases, and other protections. As a reminder, XEL historically experiences ~100 bps of regulatory lag overall, with ~75 bps from Minnesota, ~20 bps from SPS, and the remainder amongst the remaining jurisdictions.

- **On 1Q call, 2015 guidance was reaffirmed by underlying assumption changes; appears positive.** Ongoing EPS guidance for 2015 was reaffirmed at $2.00-$2.15 with seemingly favorable net assumption changes (see below). The company targets annual dividend increases of 5-7%; and a dividend payout ratio of 60-70% and does not anticipate issuing any additional equity beyond its dividend reinvestment program and benefit programs, for 2015-2019, based on its current capital expenditure plan.

Figure 209: Key assumption changes driving management EPS guidance (maintained at $2.00 – $2.15)

2015 FY Guidance Changes	New	Previous
W/A Nat Gas Sales	+0% to +1%	-2.0%
Capital Rider Revenue	Incr $155-$165M	Incr $160-$170M
Depreciation	Incr $130-$150M	Incr $160-$180M
AFUDC Equity	Decrease $30-$40M	Decrease $35-$45M

Source: Company filings

- **Filed the Integrated Resource Plan (IRP)** on Jan 2, with goal of reducing fleet carbon output by 40% by 2030. In the plan, Sherco 1&2 continue to run without scrubbers but do so less often while the company adds more renewables to the system; we had previously seen an accelerated retirement as a source of expedited potential spend – with most of the IRP incremental capex sitting beyond the current 2019 capital plan. We note that there are environmental groups that have been vocal in their desire to see the plant closed or upgraded. While management believes its compromise solution will be well received, groups may nevertheless push back by advocating for upgrade with pollution controls or retire and replace with CCGTs.

- **Independent Transcos:** formula rates have been approved by FERC. Next step is to pursue projects in the upcoming Southwest Power Pool (SPP) solicitation, although we do not expect SPP to have much work for competitive Transcos to do in this round. There was no mention of putting MN jurisdictional assets into the FERC Transco either.

- **Could we see the transmission assets moved to FERC, finally?** We see some slight opportunity to move the MN-state jurisdictional assets into FERC ratebase, or at least a proposal before regulators to do so. This would be perceived quite well given the ability to file for a forward looking test year – and stay out of general MN cases prospectively.

- **Considering the ratebasing of gas reserves and assets.** XEL is exploring the possibility of ratebasing natural gas reserves as well as pipelines for both its natural gas utility as well as its generating fleet in order to capture the current

low price environment for customers. Management expects to make a formal filing later this year or early 2016.

- **Texas electric ratecase moving along.** XEL requested a $64.75M increase based on a 10.25% ROE on $1.56B of ratebase.

- **Texas effort continues to revolve around legislative improvement:** We remain concerned around earned ROE pressure at SPS as it accelerates capex on the back of planned oil and gas-related transmission in West Texas and NM. Management is yet confident it will be able to achieve further legislative improvement in the state, focusing on implementing a forward capital rider (this is the stretch) as well as potentially cost recovery updates twice annually (as is currently allowed for ERCOT regional peers). *We remain doubtful of efforts given PUCT pushback of the concept.*

- **New electric/gas ratecase filed in Wisconsin.** On May 29, NSP-WI filed for $27M electric and $6M gas rate increases in Wisconsin based on a 10.2% ROE and 50.59% equity on $1.2B electric ratebase and $111M gas ratebase. The current authorized ROE is 10.2% and the last case decided in the state for Madison Gas and Electric in Nov 2014 also awarded a 10.2%.

- **Colorado gas ratecase staff recommendation for a -$6M decrease.** In March, the company requested a $109M increase based on a 10.1% ROE on 56% equity and $1.4B ratebase. This includes a $40.5M base rate increase for 2015 followed by $7.6M in 2016 and another $18.1M in 2017. XEL also requested increases for the Pipeline System Integrity Adjustment rider (PSIA) of $21.7M in 2016 and $21.2M in 2017. On June 24, Staff recommended a -$6.3M rate decrease based on a 9% ROE and 47.04% equity and the Office of Consumer Counsel (OCC) recommended a $5.8M increase based on a 9% ROE and 52.7% equity. Both staff and OCC oppose the multi-year step increases proposed by XEL for 2016 and 2017. Staff recommends continuing the PSIA rider through 2017 and OCC recommended terminating it in June 2016.

Regulatory risk declining significantly in 1H15

To summarize what's was done and dusted over 1Q15:

- Minnesota Multi-Year Electric Rate Case – Resolved in March

- Monticello EPU/LCM Prudence Filing – Resolved in March

- Colorado Multi-year Electric Rate Case – Resolved in February

While we are increasingly impressed with the execution of regulatory strategy at XEL, we remain Neutral rated on a slower build-up for competitive transmission and wariness toward larger-cap utilities at recent P/E levels.

While we are increasingly impressed with the execution of regulatory strategy at XEL, we remain Neutral rated on a slower build-up for competitive transmission and wariness toward larger-cap utilities at recent P/E levels. Resolution of the Monticello prudency and the Minn ratecase in March, as well as a multi-year settlement in Colorado, significantly reduce regulatory risk, with ~68% of ratebase under multi-year rate plans. Currently earning in the mid-8%'s ROE, the company plans to further reduce regulatory lag through legislative initiatives, particularly in Minnesota where ~75% of such lag originates. Ultimately, management hopes to improve earned ROE by 50 bps by 2018 to achieve a $0.11 EPS and 1% growth improvement opportunity through a variety of such legislative and regulatory measures.

Expect another MN rate case in 2016 to reflect wind investments

The MPUC did not adopt the company's proposal to avoid a 2016 rate case, so XEL is preparing for a 2016 rate case filing around November 1 so that interim rates for 2016 can go into effect on Jan 1st 16. The case would reflect investments made in ratebase and PPA wind parks, for which the new legislation will hopefully allow the company to establish a baseline for a formula approach. At a minimum, with no real issues relating to development of the wind parks, the case should prove less controversial than the latest case with the cost over-runs relating to Monticello nuclear uprate. Moreover, with its authorized ROE recently revised to 9.72%, downside risk is more limited.

2015E-2018E estimates largely unchanged

Figure 210: UBS Estimates for XEL, 2014E-2018E

UBS Estimates ($/share)	2014A	2015E	2016E	2017E	2018E
PSCo	$0.90	$0.93	$0.98	$1.04	$1.08
NSPM	0.80	0.87	0.89	0.91	0.93
SPS	0.26	0.26	0.29	0.33	0.36
NSPW	0.14	0.14	0.16	0.17	0.17
XEL Parent	(0.08)	(0.09)	(0.09)	(0.09)	(0.09)
UBSe EPS	$2.03	$2.09	$2.22	$2.34	$2.43
CAGR 2013-xxxx				*5.3%*	*5.1%*
Guidance		*2.00-2.15*			*4-6%*
Previous Ests		$2.09	$2.21	$2.34	$2.44
Consensus		$2.09	$2.22	$2.36	$2.52

Source: Company Filings, FactSet, and UBS Estimates

Valuation: Reduce PT $1 to $35 for lower peer P/E multiple

Our SOP is based on a 2017E average utility P/E methodology with a premium ascribed to Wisconsin (1.0x turn) and a discount for the Southwest (0.5x turn). For Minnesota, we previously removed the -1.0x discount we had applied given the resolution of both Monticello as well as the ratecase.

Figure 211: XEL Valuation

			Low Case		Base Case			High Case	
Business Segment	**Valuation Metric**	**2017 EPS**	**Valuation Multiple**	**($/Share) Value**	**Premium/ Discount**	**Valuation Multiple**	**($/Share) Value**	**Valuation Multiple**	**($/Share) Value**
Regulated Business						**Regulated Peers:**	14.7x		
Northern States Power - Minnesota	P/E	$0.91	13.7x	$12.50	0.0x	**14.7x**	$13.42	15.7x	$14.33
Northern States Power - Wisconsin	P/E	$0.17	14.7x	$2.43	1.0x	**15.7x**	$2.60	16.7x	$2.77
Public Service Colorado	P/E	$1.04	13.7x	$14.29	0.0x	**14.7x**	$15.34	15.7x	$16.38
Southwestern Power Service	P/E	$0.33	13.2x	$4.35	-0.5x	**14.2x**	$4.67	15.2x	$5.00
HoldCo									
Parent & Other Overhead Expense	P/E	($0.09)	14.0x	($1.20)		14.7x	($1.26)	15.4x	($1.33)
XEL Equity Value per Share		**$2.36**		**$32.00**		*14.8*	**$35.00**		**$37.00**

Source: Company Filings, FactSet, and UBS Estimates

EFH (Unrated)

Oncor Process Trudges Towards Potential Resolution

- In late June Energy Future Holdings (EFH) Corp notified the Bankruptcy Court requesting to termination the auction process for its ownership stake in the T&D utility Oncor. The latest rejection of the Oncor auction process is a negative for NextEra Energy which has publicly expressed interest in the past. We suspect any other group would still ultimately want to partner with Hunt and HIFR, rather than pursuing their own REIT structure.

- Hunt Consolidated and related party InfraREIT (HIFR) have disclosed in recent SEC filings that Hunt is involved in the bankrptucy process regarding a potential acquisition of Oncor.

- The latest proposal would *no longer* include any kind of contingency around regulatory approval of a REIT structure (previously reflected in second-lien EFIH restructuring proposal). Given the need to receive PUCT approval, we do not see this as a trivial contingency.

- According to the Wall Street Journal the credits bid is valued at ~$19Bn although a key element remains how TCEH unsecured creditors would *fund* the acquisition of Oncor (they would likely emerge with merely the *right* to buy the structure at a ~$19 Bn valuation). This could allow creditors to opt to take equity in the Oncor structure in lieu of being taken out in cash and some amount of accrued interest.

What's the timeline? Looking good on resolution

We understand from media reports that a plan could be slated for approval as soon as October should creditors succeed in hashing out the latest deal with unsecured creditors, providing a path for completion meaningfully ahead of more pessimistic Street views. Resolution of Oncor will provide clearer line of site to addressing the remaining competitive business – here the key question is how the company will exit its ongoing restructuring, via IPO or a sale?

EFH: What does this mean for DYN?

We see some semblance of resolution around the bankruptcy as a positive for shares of Dynegy, as we continue to see the company's expression of eventual interest to gain exposure to Texas as driving continued interest in the only eligible significant counterparty, TCEH (the competitive side of the EFH business). Akin to the process pursued over the Oncor assets, the question remains whether TCEH will pursue a formal sales process of bilaterally negotiate a sale to creditors.

EFH: What does this mean for NEE?

On the pursuit of another target to fill the gap lost via Oncor

CNP is the only *other* large TX utility

We see the latest developments as firmly setting back management's latest strategic ambitions. The question now reverts to what *other* candidates might management be interested in as NEE has been involved in M&A (current pending Hawaii Electric deal) and has surplus cash flows from its NEP YieldCo guided dropdowns? A delay in a regulated transaction would also put the brakes on mgmt's ability to deploy capital into more risky midstream ventures with a higher risk profile (for instance, G&P). Our scenario analysis below illustrates that making a deal accretive would be difficult without the use of at least 40% leverage,

assuming a nominal 1% O&M synergies (which itself might be tough to eke out given the geographic distance).

EFH Debt: Continues Gap Down

We include EFH bank debt below, relevant given similarities to NRG equity.

Figure 212: EFH Latest Bank Debt (Extended 2017 Term Loan)

Source: Bloomberg

We think ~2017 is the bottom in ERCOT

Limited new build beyond 2017 coupled with roll-off of tax credits and potential early retirements

By mid-2015, we could see companies begin to pull back on further development activities as the PTC & ITC window close, driving a bottoming in this market by late 2016 and into 2017. Many developers already appear to be 'full' on their exposure to the state – and others are likely to face challenges in pursuing contracted build, and especially merchant build. With PJM in favor over ERCOT, we could well paint a story for a reversal in these attitudes by 2017-2018 with meaningful new build reaching in service in PJM while ERCOT sees an abrupt end to its new entrants.

Below we show updated (MtM for commodity moves) EFH projections disclosed by the company.

Figure 213: Updated EFH MtM projections using company disclosed of financials 8k

EFH Corp Mini-Model Projections using Mgmt Projections and Updating using MtM Commodities	2013	2014	2015	2016	2017	2018
TCEH Consolidated Adjusted EBITDA (from 4-29-14 8k), using 8/30 Co	**2,721**	**2,109**	**1,656**	**1,587**	**1,850**	**1,942**
Subtract: TXU Energy (using 2012 Guidance midpt & projected Yo\	**719**	619	589	559	544	529
Implied Generation (Luminant) EBITDA	**2,002**	**1,490**	**1,067**	**1,028**	**1,306**	**1,413**
Hedge Value (Disclosed) - 10/15/13 8K	1,018	(587)	0	0	0	0
Implied Open EBITDA Generation (Luminant) , using 8k	**984**	**2,077**	**1,067**	**1,028**	**1,306**	**1,413**
O&M (UBSe)	875	875	875	875	875	875
Implied Open Generation GM	**1,859**	**2,952**	**1,942**	**1,903**	**2,181**	**2,288**
Implied Open Revenue	2,879	3,963	2,992	3,071	3,360	3,479
Expected Generation TWh *(Mgmt Projection from from 4-29-14 8k)*	**70**	**68**	**68**	**72**	**72**	**72**
Nuclear TWh (UBSe)	19	18	19	18	18	18
Coal TWh (Implied)	51	50	49	54	54	54
Total Coal Capacity (MW), Monticello 1&2 for Summer-Only (33%)	7,303					
Implied Capacity Factor on Coal (%)	80%					
Open Revenues (Est. Using Premium to ERCOT Prices)	2,520	2,564	2,693	2,964	3,286	3,288
ERCOT-North (ATC), as of Aug 30th, 2013	34.28	36.26	38.45	40.36	45.19	45.67
Houston Shipping Channel Gas, as of Aug 30th 2013	3.45	3.88	4.08	4.20	4.31	4.44
ERCOT-North Premium (% over ATC)	5%	4%	3%	2%	1%	0%
Realized Power Price ($/MWh)	35.99	37.71	39.60	41.17	45.64	45.67
Nuclear Dispatch Costs ($/MWh)	7	7	7	7	7	7
Coal Dispatch Costs ($/MWh)	20	20.21	21.42	21.63	21.84	22.05
Implied Delivered PRB Price ($/t), UBSe	38	39	40	41	42	43
Implied Delivery Price ($/t), UBSe	27	28	29	30	31	32
Fuel Cost (Only Coal/Nuclear Fuel Excl from Adj. EBITDA)	1,020	1,011	1,050	1,168	1,179	1,191
Baseload-Only Gross Margin (UBSe), as of Feb 1st	**1,500**	**1,554**	**1,643**	**1,796**	**2,107**	**2,098**
Asset Management, *using this as Plug to Mgmt*	**359**	**1,398**	**299**	**107**	**74**	**190**
Open Luminant EBITDA (UBSe), as of Feb 1st	625	679	768	921	1,232	1,223
Add : Hedges (As disclosed by Mgmt) - 4/29/14 8K	1,018	(587)	-	-	-	-
Hedged Luminant (Generation) EBITDA (UBSe), as of Feb 1st	2,002	1,490	1,067	1,028	1,232	1,223
Add : TXU Energy, Retail Business EBITDA (from above)	719	619	589	559	544	529
Hedged TCEH EBITDA (UBSe), as of Feb 1st 8k	2,721	2,109	1,656	1,587	1,776	1,752
Implied All-in Fuel, O&M, SG&A Costs ($/MWh)	27	28	28	28	29	29
Guidance	30-32					
ERCOT-North (ATC) - MtM		39.80	31.13	30.12	31.45	32.55
Reflecting the Latest Commodity Shifts						
ERCOT-North (ATC) - MtM Improvement/(Declines), $/MWh		3.54	(7.32)	(10.24)	(13.74)	(13.12)
Volumes		68	68	72	72	72
Change in Hedge Value since Feb 1st		241	(498)	(737)	(989)	(945)
Hedged TCEH EBITDA (Mgmt Projections), using latest MtM		**2,350**	**1,158**	**850**	**861**	**997**
Nuclear Fuel (Not Included in Mgmt's EBITDA), UBSe		(126)	(133)	(126)	(126)	(126)
Maintenance/Enviro Capex (Plug from Nuclear Fuel vs. Mgmt Total)		(228)	(472)	(369)	(329)	(602)
TCEH FCF (Pre-Other CF Items)		**1,996**	**553**	**355**	**406**	**269**
Working Capital		41	(29)	1	-	-
Margin Deposits		(322)	-	-	-	-
Other CF Items		(104)	(27)	(51)	(51)	-
State Tax Payments		(30)	(29)	(26)	(26)	(26)
TCEH FCF (Pre-Interest), using Mgmt Projections / UBSe for Capex & Fuel		**1,581**	**468**	**279**	**329**	**243**
FCF Yield on Bank Debt		**13.6%**	**3.8%**	**2.4%**	**2.8%**	**1.8%**

Source: Company Filings and UBS Estimates

Calpine Corporation

2Q15 Playbook: Reflecting Summer Slump

Reducing our Price Target $4 as part of Quarterly Earnings Preview update

In conjunction with our 2Q15 Earnings Preview, we have updated our commodity price deck which has a material impact on the IPPs we cover: Dynegy, Calpine, and NRG Energy. Power and natural gas prices have weakened significantly in the last two months which has sent PJM-W ATC forward pricing ~5% lower in 2016/2017 with Henry Hub expectations also declining ~3%. PJM-W ATC is trading at $37/MWh versus $40/MWh at this point last year and threatening the sustained lows of December 2013. ERCOT-Houston ATC pricing has tumbled ~5% as well since May and 2016 forwards are flirting with breaching the $30/MWh level (ERCOT-North and –West have already fallen below). $40MWh power prices in Texas appear like a distant memory.

EBITDA estimates declining across-the-board

Our revised EBITDA estimates for 2015/2016/2017 are $2,055Mn/$1,848Mn/$1,879Mn from $1,984/$1,896/$1,930 previously versus Consensus of $1,976Mn/$1,983/$2,036Mn Guidance for 2015 is $1,900-$2,100Mn.

How are we positioned on shares?

With sparks off meaningfully of late in Texas – and now PJM as well – we understand why shares are trading off. We are surprised by the magnitude, albeit suspect with shares trading primarily around shifts in energy margins, we are hard pressed to 'call a bottom'. We think PJM spark spreads are likely to 'crest' in 2015, with more plant additions contemplated in 2016-2018, serving as a headwind for spark formation. On Texas, we suspect the bottom is likely more of a ~2016 phenomenon. Similarly, California also appears to have 'topped' out for the time being, with prices continuing to decline for forward deliveries with expectations for renewables deployment only growing. The question remains whether improved capacity prices in PJM will help shore up shares alongside meaningful further switching YoY across all markets. We see shares as cheap (albeit not significantly) vs. historic implied multiples

Valuation: Reduce Price Target to $19; Maintain Neutral

Valuation remains based on 2016E sum-of-the-parts methodology.

Equities

Americas
Electric Utilities

12-month rating	**Neutral**
12m price target	**US$19.00**
	Prior: US$23.00
Price	**US$17.54**

RIC: CPN.N **BBG:** CPN US

Trading data and key metrics

52-wk range	US$24.29-17.37
Market cap.	US$6.70bn
Shares o/s	382m (COM)
Free float	70%
Avg. daily volume ('000)	844
Avg. daily value (m)	US$16.7
Common s/h equity (12/15E)	US$3.21bn
P/BV (12/15E)	2.0x
Net debt / EBITDA (12/15E)	5.0x

EPS (UBS, diluted) (US$)

	12/15E			
	From	To	% ch	Cons.
Q1	(0.03)	(0.03)	0.00	(0.17)
Q2E	0.06	(0.08)	-227.83	(0.02)
Q3E	0.84	1.23	46.23	0.63
Q4E	(0.02)	(0.31)	-1,324.49	0.08
12/15E	0.86	0.81	-5.93	0.74
12/16E	0.75	0.64	-14.05	0.88
12/17E	1.00	0.83	-17.28	1.24

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Highlights (US$m)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Revenues	5,478	6,301	8,030	6,318	6,067	6,604	6,904	7,223
EBIT (UBS)	995	997	1,112	1,187	990	1,033	1,053	1,143
Net earnings (UBS)	251	266	401	292	215	254	278	355
EPS (UBS, diluted) (US$)	0.53	0.60	0.98	0.81	0.64	0.83	1.00	1.42
DPS (US$)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net (debt) / cash	(9,466)	(10,171)	(10,565)	(10,254)	(10,083)	(9,869)	(9,631)	(9,296)

Profitability/valuation	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
EBIT margin %	18.2	15.8	13.8	18.8	16.3	15.6	15.3	15.8
ROIC (EBIT) %	7.8	7.7	8.5	9.3	8.1	8.9	9.5	10.8
EV/EBITDA (core) x	9.5	9.8	9.0	7.4	8.6	8.4	8.2	7.8
P/E (UBS, diluted) x	31.9	33.0	22.3	21.7	27.2	21.1	17.5	12.4
Equity FCF (UBS) yield %	0.2	(0.3)	3.9	13.6	10.8	11.4	11.8	13.2
Net dividend yield %	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Source: Company accounts, Thomson Reuters, UBS estimates. UBS adjusted EPS is stated before goodwill-related charges and other adjustments for abnormal and economic items at the analysts' judgement. Valuations: based on an average share price that year, (E): based on a share price of US$17.54 on 13 Jul 2015 19:39 EDT

Dynegy, Inc.

2Q15 Playbook: Reflecting Summer Slump

Reducing our Price Target $3 as part of Quarterly Earnings Preview update

In conjunction with our 2Q15 Earnings Preview, we have updated our commodity price deck which has a material impact on the IPPs we cover: Dynegy, Calpine, and NRG Energy. Power and natural gas prices have weakened significantly in the last two months which has sent PJM-W ATC forward pricing ~5% lower in 2016/2017 with Henry Hub expectations also declining ~3%. PJM-W ATC is trading at $37/MWh versus $40/MWh at this point last year and threatening the sustained lows of December 2013.

EBITDA estimates declining across-the-board

Our revised EBITDA estimates for 2015/2016/2017 are $987Mn/$1,187Mn/$1,222Mn from $1,046Mn/$1,226 Mn /$1,252 Mn previously versus Consensus of $1,009Mn/$1,291Mn/$1,283Mn. Guidance for 2015 is $825-$1,025Mn.

How are we positioned on shares?

We continue to rate Dynegy a Buy despite recent weakness as we expect positive 'internal' updates later this year (material positive synergy update and capital allocation) as well as beneficially 'external' datapoints (PJM auction results and possibility of regional nuclear retirements).

Valuation: Reduce Price Target to $37; Maintain Buy

Valuation remains based on 2017E sum-of-the-parts methodology.

Equities

Americas
Electric Utilities

12-month rating	Buy
12m price target	US$37.00
	Prior: US$40.00
Price	US$29.50

RIC: DYN.N **BBG:** DYN US

Trading data and key metrics

52-wk range	US$34.76-26.06
Market cap.	US$2.95bn
Shares o/s	100m (COM)
Free float	100%
Avg. daily volume ('000)	413
Avg. daily value (m)	US$13.3
Common s/h equity (12/15E)	US$4.18bn
P/BV (12/15E)	0.9x
Net debt / EBITDA (12/15E)	6.0x

EPS (UBS, diluted) (US$)

	12/15E			
	From	To	% ch	Cons.
Q1	(0.87)	(0.69)	20.18	(1.49)
Q2E	(1.18)	(0.78)	33.68	(0.48)
Q3E	(0.60)	0.84	238.26	0.60
Q4E	3.02	0.73	-75.97	0.98
12/15E	0.37	0.11	-69.48	(0.16)
12/16E	1.00	0.84	-16.51	2.10
12/17E	1.16	1.04	-10.88	2.01

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Highlights (US$m)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Revenues	1,293	1,466	2,497	3,972	5,390	5,379	5,587	5,437
EBIT (UBS)	(97)	(309)	(51)	559	739	786	1,038	1,052
Net earnings (UBS)	(224)	(359)	(278)	14	109	135	274	281
EPS (UBS, diluted) (US$)	(2.24)	(3.59)	(2.78)	0.11	0.84	1.04	2.10	2.16
DPS (US$)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net (debt) / cash	(1,067)	(1,149)	(6,226)	(5,946)	(5,501)	(5,085)	(4,704)	(4,314)

Profitability/valuation	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
EBIT margin %	-7.5	-21.1	-2.0	14.1	13.7	14.6	18.6	19.3
ROIC (EBIT) %	(2.8)	(8.9)	(0.7)	5.4	7.1	7.8	10.5	10.8
EV/EBITDA (core) x	27.7	14.9	12.6	9.6	8.0	7.7	6.5	6.4
P/E (UBS, diluted) x	(2.3)	(5.9)	(10.2)	NM	35.3	28.5	14.1	13.7
Equity FCF (UBS) yield %	(62.8)	6.9	6.0	(14.2)	15.1	14.1	12.9	13.2
Net dividend yield %	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Source: Company accounts, Thomson Reuters, UBS estimates. UBS adjusted EPS is stated before goodwill-related charges and other adjustments for abnormal and economic items at the analysts' judgement. Valuations: based on an average share price that year, (E): based on a share price of US$29.50 on 13 Jul 2015 19:39 EDT

NRG Energy Inc.

2Q15 Playbook: Reflecting Summer Slump

Reducing our Price Target $5 as part of Quarterly Earnings Preview update

In conjunction with our 2Q15 Earnings Preview, we have updated our commodity price deck which has a material impact on the IPPs we cover: Dynegy, Calpine, and NRG Energy. Power and natural gas prices have weakened significantly in the last two months which has sent PJM-W ATC forward pricing ~5% lower in 2016/2017 with Henry Hub expectations also declining ~3%. PJM-W ATC is trading at $37/MWh versus $40/MWh at this point last year and threatening the sustained lows of December 2013. ERCOT-Houston ATC pricing has tumbled ~5% as well since May and 2016 forwards are flirting with breaching the $30/MWh level (ERCOT-North and –West have already fallen below). $40MWh power prices in Texas appear like a distant memory.

EBITDA estimates declining across-the-board

Our revised EBITDA estimates for 2015/2016/2017 are $3,288Mn/$2,953Mn/$2,706Mn from $3,368Mn/$2,096Mn/$2,858Mn previously versus Consensus of $3,297Mn/$3,103Mn/$2,932Mn. Guidance for 2015 is the top-quartile of the $3,200-$3,400Mn range.

How are we positioned on shares?

Although we are reducing our price target on the back of lower power prices, we still see value in shares. Aside from the obvious potential recovery in power prices and upcoming PJM capacity market datapoints, we see upside to our valuation at the Home Solar subsidiary where we reflect just $2/sh for the near-term targets. A potential offset is that we still value GenOn at ~$2/sh despite the challenged free cash flow profile and concerns about the expected economic life of some underlying units. We see NRG as meriting greater attention at these levels, given its more Western orientation to PRB coal.

Valuation: Reduce Price Target to $25; Maintain Buy

Valuation remains based on 2016E sum-of-the-parts methodology

Equities

Americas
Electric Utilities

12-month rating	Buy
12m price target	US$25.00
	Prior: US$30.00
Price	US$22.23
RIC: NRG.N BBG: NRG US	

Trading data and key metrics

52-wk range	US$33.72-21.76
Market cap.	US$7.47bn
Shares o/s	336m (COM)
Free float	100%
Avg. daily volume ('000)	812
Avg. daily value (m)	US$20.0
Common s/h equity (12/15E)	US$11.8bn
P/BV (12/15E)	0.6x
Net debt / EBITDA (12/15E)	5.3x

EPS (UBS, diluted) (US$)

	12/15E			
	From	To	% ch	Cons.
Q1	(0.40)	(0.40)	0.00	(0.37)
Q2E	(0.12)	(0.15)	-23.03	(0.07)
Q3E	1.30	1.25	-3.98	0.63
Q4E	1.61	1.53	-5.01	0.12
12/15E	2.46	2.29	-6.80	0.80
12/16E	1.82	1.54	-15.61	0.17
12/17E	1.70	1.36	-19.81	(0.29)

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Highlights (US$m)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Revenues	8,422	11,295	15,868	16,278	15,974	15,761	15,819	15,979
EBIT (UBS)	969	1,380	1,605	2,156	1,816	1,623	1,657	1,813
Net earnings (UBS)	579	274	262	726	487	431	479	708
EPS (UBS, diluted) (US$)	2.47	0.85	0.78	2.29	1.54	1.36	1.51	2.24
DPS (US$)	0.18	0.48	0.54	0.58	0.58	0.58	0.58	0.58
Net (debt) / cash	(14,042)	(14,812)	(18,568)	(17,450)	(16,301)	(14,926)	(13,359)	(11,311)

Profitability/valuation	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
EBIT margin %	11.5	12.2	10.1	13.2	11.4	10.3	10.5	11.3
ROIC (EBIT) %	6.5	7.4	7.9	10.3	9.0	8.5	9.2	10.9
EV/EBITDA (core) x	6.2	6.3	6.2	4.9	5.0	5.0	4.3	3.4
P/E (UBS, diluted) x	7.5	31.3	39.6	9.7	14.4	16.3	14.7	9.9
Equity FCF (UBS) yield %	(50.4)	(9.1)	5.9	6.8	7.9	10.9	13.5	19.9
Net dividend yield %	0.9	1.8	1.7	2.6	2.6	2.6	2.6	2.6

Source: Company accounts, Thomson Reuters, UBS estimates. UBS adjusted EPS is stated before goodwill-related charges and other adjustments for abnormal and economic items at the analysts' judgement. Valuations: based on an average share price that year, (E): based on a share price of US$22.23 on 13 Jul 2015 19:39 EDT

Dynegy, Inc. Investment case

Dynegy shares are likely to be driven by moves in gas and power prices as well as by announcements with respect to financial restructuring/M&A considerations as peer coal and gas generators weigh selling their coal portfolios. Equity valuation is driven in part by option value to either a power recovery. We think the shares will outperform as the strategy is executed by the new management at the helm, led by Bob Flexon, who previously served as NRG Energy's CFO/COO.

Calpine Corporation Investment case

Calpine has numerous opportunities related to its exposure to the Texas power markets, California carbon via its geothermal assets, and increased coal-to-gas switching in the Southeast. Despite an uncertain political climate and the apparent stalling of capacity market reforms, we still view Texas as among the US power market with the most upside, given its tight supply forecast, fast growing economy. In the Southeast, we believe monetization of its fleet via long-term contracts or outright sales to regulated utilities will drive further upside, as the recent LS Power deal indicates. Our price target remains derived via EV/EBITDA sum-of-the-parts analysis.

NRG Energy Inc. Investment case

Shares remain particularly levered to natural gas prices through its large coal portfolio in Texas; that said, we look for market reforms in ERCOT to improve heat rates independent of natural gas prices. NRG is exposed to Texas market reforms, which is our top theme in the sector. We think the name may be appealing to those seeking substantial leverage to gas and power prices.

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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12-Month Rating	**Definition**	**Coverage**[1]	**IB Services**[2]
Buy	FSR is > 6% above the MRA.	45%	36%
Neutral	FSR is between -6% and 6% of the MRA.	42%	32%
Sell	FSR is > 6% below the MRA.	13%	20%
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 30 June 2015.
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.
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UBS Securities LLC: Julien Dumoulin-Smith; Michael Weinstein; Paul Zimbardo.

Company Disclosures

Company Name	Reuters	12-month rating	Short-term rating	Price	Price date
AES Corporation[16]	AES.N	Neutral	N/A	US$13.12	14 Jul 2015
Ameren Corp.[16]	AEE.N	Neutral	N/A	US$38.86	14 Jul 2015
American Electric Power, Inc.[2, 4, 6a, 6b, 7, 16]	AEP.N	Neutral	N/A	US$55.19	14 Jul 2015
Avista Corp[2, 4, 6a, 6c, 7, 16]	AVA.N	Neutral	N/A	US$31.82	14 Jul 2015
Calpine Corporation[2, 4, 6a, 16]	CPN.N	Neutral	N/A	US$17.63	14 Jul 2015
CMS Energy Corporation[16]	CMS.N	Buy	N/A	US$33.76	14 Jul 2015
Consolidated Edison[16]	ED.N	Sell	N/A	US$60.42	14 Jul 2015
Dominion Resources[2, 4, 5, 6a, 6b, 6c, 7, 16]	D.N	Buy	N/A	US$69.20	14 Jul 2015
DTE Energy Co.[2, 4, 5, 6a, 16]	DTE.N	Buy	N/A	US$77.10	14 Jul 2015
Duke Energy[4, 5, 6a, 6c, 7, 16]	DUK.N	Neutral	N/A	US$73.80	14 Jul 2015
Dynegy, Inc.[2, 4, 5, 6a, 16]	DYN.N	Buy	N/A	US$29.49	14 Jul 2015
Edison International[2, 4, 5, 6a, 16]	EIX.N	Buy	N/A	US$57.94	14 Jul 2015
Empire District Electric Company[16]	EDE.N	Sell	N/A	US$22.54	14 Jul 2015
Entergy Corp.[16]	ETR.N	Neutral	N/A	US$72.29	14 Jul 2015
Eversource Energy[13, 16]	ES.N	Neutral	N/A	US$47.30	14 Jul 2015
Exelon Corp.[4, 6a, 6c, 7, 16]	EXC.N	Neutral	N/A	US$32.77	14 Jul 2015
FirstEnergy Corp.[16]	FE.N	Sell	N/A	US$33.62	14 Jul 2015
ITC Holdings Corp[13, 16]	ITC.N	Neutral	N/A	US$33.38	14 Jul 2015
NextEra Energy[2, 4, 6a, 16]	NEE.N	Buy	N/A	US$101.99	14 Jul 2015
NextEra Energy Partners LP[2, 4, 5, 6a, 16]	NEP.N	Neutral	N/A	US$39.99	14 Jul 2015
NRG Energy Inc.[16]	NRG.N	Buy	N/A	US$22.08	14 Jul 2015
NRG Yield[16]	NYLDa.N	Neutral	N/A	US$21.95	14 Jul 2015
PG&E Corporation[16]	PCG.N	Neutral	N/A	US$51.00	14 Jul 2015
Pinnacle West Capital Co.[6a, 16]	PNW.N	Buy	N/A	US$60.11	14 Jul 2015
PPL Corporation[2, 4, 6a, 6c, 7, 16]	PPL.N	Neutral	N/A	US$30.99	14 Jul 2015
Public Service Enterprise Group[16]	PEG.N	Neutral	N/A	US$40.88	14 Jul 2015
SCANA Corp.[2, 4, 5, 6a, 16]	SCG.N	Neutral	N/A	US$52.78	14 Jul 2015
Sempra Energy[2, 4, 5, 6a, 16, 18]	SRE.N	Buy	N/A	US$101.98	14 Jul 2015
Southern Company[2, 4, 6a, 16]	SO.N	Sell	N/A	US$43.21	14 Jul 2015
TECO Energy Inc.[16]	TE.N	Buy	N/A	US$18.52	14 Jul 2015
WEC Energy Group Inc.[16]	WEC.N	Neutral	N/A	US$47.22	14 Jul 2015
Westar Energy, Inc.[6a, 16]	WR.N	Neutral	N/A	US$35.93	14 Jul 2015
Xcel Energy Inc.[6a, 16]	XEL.N	Neutral	N/A	US$33.54	14 Jul 2015

Source: UBS. All prices as of local market close.
Ratings in this table are the most current published ratings prior to this report. They may be more recent than the stock pricing date

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