US Electric Utilities & IPPs 3Q14 Preview

3Q14 Earnings Playbook: Trading Tips for Turbulent Times

Equities

Americas
Electric Utilities

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It's the best and worst of times to be a Utility

Despite the market volatility of the sector in recent days – and shift away from the diversified and IPP themes right back to defensive utilities, we see the fundamental outlook for the competitive segment as particularly constructive. The backdrop of ongoing power reforms and resilient heat rates (up 20% QoQ in PJM) begs the broader question of when the power sector will 'peak'? We think likely next year. While gas basis – and the winter premium remain our biggest concern, we see compelling arguments around select value. In the interim, regulated utilities are back en vogue – and see recent moves as appearing indiscriminate, offering investors the opportunity to hide in higher quality utilities that failed to participate (and could revise guidance).

Don't expect big surprises at EEI or with 3Q guidance

Looking ahead to the annual gathering in mid-November following 3Q results, we see few significant surprises on guidance. On the EPS front, we see a generally unfavorable skew amidst largely mild weather, with warnings around these headwinds already dropped upon investors throughout 3Q. Despite the pressure, we still see companies raising their guidance with **ED, EXC, PSEG, and PPL** potentially raising '14 guidance ranges. Meanwhile **DYN and AEP** are poised to raise '15 (and even '16 expectations). Focusing on 3Q, we see CPN, DUK, EIX, EDE, and SRE as potential beats, where as we see D, DTE, NEE, NU, PNW, and XEL as potential misses.

Power on the cheap? DYN remains clearest way to play reforms

While 3Q results across the IPP sector are likely to be lackluster, we see upside to guidance for one company, **Dynegy**, with the potential to revise its '15 EBITDA range upwards by $100-200 Mn. Elsewhere, we see **CPN** and **NRG** '15 guidance as inline with Street expectations at $1.9-2.1 Bn and $3.2-3.4 Bn, respectively (including NYLD's Alta acquisition). **AES** too appears increasingly attractive, but see EPS at the very bottom of its EPS range ($1.30) for '14, coupled with continued headwinds into '15 as limiting appreciation potential; capital deployment is the clear wildcard here.

How to Play the Sector? The 'better' regulated utilities

We're biased to like our tactical regulated names, emphasizing our Buy-rated names like **DUK** and **PNW**. With both companies slated to see positive catalysts into 2H, they remain among our best defensive ideas. Other higher quality regulated names with catalysts include **ConEd** on the back of continued execution of potentially constructive reforms, **AEP** ahead of resolution on its ESP filing, GenCo divestment, and higher EEI guidance, and even **XEL** ahead of multiple rate case resolution. Elsewhere, we are surprised that higher risk diversified utilities have seen bids of late including **FE** and **ETR** on the back of the rally. We maintain SO could yet see its shares bid-up, despite widespread low expectations for Kemper and Vogtle.

Infrastructure thesis on hiatus, but better balance sheets will count

With infra thesis under some pressure due to compression in MLP and YieldCo multiples- and broader concerns over LNG exports – we see the other side of the trade still shining. We continue to see structural upside to forward estimates for all of our infrastructure coverage, emphasizing upside to D's long-term growth rate at its Analyst Day next Feb, and upside to forward estimates for NEE in 2016 (and beyond). We believe these equities will act increasingly defensive, particularly large-caps NEE and D, amidst concerns elsewhere.

Earnings & Price Target Snapshot

Figure 1: Changes to Ratings, Price targets and Estimates

Changes to Ratings, Price targets and Estimates		Price	Rating		Price target		2014E EPS*		2015E EPS*		2016E EPS*	
Company	RIC	13-Oct-14	New	Old	New	Old	New	Old	New	Old	New	Old
AES Corporation	AES.N	13.14	Neutral	Neutral	15.00	15.00	**1.30**	1.31	**1.33**	1.36	**1.46**	1.48
Ameren	AEE.N	40.03	Neutral	Neutral	40.00	40.00	2.39	2.39	2.54	2.54	2.70	2.70
American Electric Po	AEP.N	54.23	Neutral	Neutral	**55.00**	56.00	**3.48**	3.54	3.66	3.66	**3.80**	3.79
Avista	AVA.N	32.10	Neutral	Neutral	30.00	30.00	1.93	1.93	1.98	1.98	2.07	2.07
Calpine*	CPN.N	20.80	Neutral	Neutral	24.00	24.00	1,967	1,967	2,022	2,022	1,907	1,907
Consolidated Edison	ED.N	59.82	Neutral	Neutral	**59.00**	55.00	**3.81**	3.78	**3.86**	3.85	**3.95**	3.94
Dominion	D.N	69.99	Buy	Buy	82.00	82.00	3.48	3.48	3.92	3.92	4.18	4.18
DTE Energy	DTE.N	78.90	Neutral	Neutral	78.00	78.00	4.41	4.41	4.60	4.60	5.00	5.00
Duke Energy	DUK.N	77.41	Buy	Buy	81.00	81.00	4.64	4.64	4.81	4.81	5.05	5.05
Dynegy*	DYN.N	28.11	Buy	Buy	**43.00**	36.00	**372**	372	**468**	399	**464**	414
Edison International	EIX.N	58.14	Buy	Buy	60.00	60.00	3.97	3.97	3.53	3.53	3.93	3.93
Empire District	EDE.N	25.21	Neutral	Neutral	24.00	24.00	**1.48**	1.47	**1.56**	1.55	**1.62**	1.59
Entergy	ETR.N	78.68	Neutral	Neutral	77.00	77.00	**6.04**	6.03	**5.15**	5.10	**5.82**	5.57
Exelon	EXC.N	34.11	Neutral	Neutral	**35.00**	31.00	**2.45**	2.50	**2.80**	2.73	**2.78**	2.66
FirstEnergy	FE.N	35.10	Sell	Sell	**26.00**	24.00	**2.47**	2.43	**2.90**	2.85	**2.82**	2.72
Hannon Armstrong	HASI.N	13.26	Buy	Buy	16.00	16.00	0.96	0.96	1.15	1.15	1.32	1.32
ITC Holdings	ITC.N	35.10	Buy	Buy	39.00	39.00	1.87	1.87	1.94	1.94	2.24	2.24
NextEra Energy	NEE.N	92.79	Buy	Buy	**102.00**	108.00	**5.25**	5.38	**5.96**	5.94	**6.41**	6.38
NextEra Energy LP	NEP.N	30.24	Neutral	Neutral	34.00	34.00	0.67	0.67	0.82	0.82	0.88	0.88
Northeast Utilities	NU.N	46.77	Buy	Buy	50.00	50.00	2.70	2.70	2.91	2.91	3.16	3.16
NRG Energy*	NRG.N	29.13	Buy	Buy	35.00	35.00	**3,290**	3,281	**3,338**	3,160	**3,244**	3,038
NRG Yield	NYLD.N	43.14	Neutral	Neutral	54.00	54.00	1.80	1.80	2.08	2.08	2.17	2.17
PG&E Corp.	PCG.N	45.37	Neutral	Neutral	46.00	46.00	3.07	3.07	**3.17**	3.14	**3.29**	3.24
Pinnacle West Captl	PNW.N	57.10	Buy	Buy	60.00	60.00	3.75	3.75	3.87	3.87	4.00	4.00
PPL Corp.	PPL.N	33.64	Neutral	Neutral	36.00	36.00	**2.31**	2.26	2.34	2.34	2.37	2.37
Public Service Entrp	PEG.N	38.05	Neutral	Neutral	40.00	40.00	**2.72**	2.74	**2.67**	2.68	**2.73**	2.69
SCANA Corp.	SCG.N	49.89	Neutral	Neutral	52.00	52.00	3.65	3.65	3.75	3.75	3.92	3.92
Sempra Energy	SRE.N	102.67	Buy	Buy	**116.00**	111.00	**4.54**	4.52	**4.82**	4.81	**5.12**	5.09
Southern Company	SO.N	45.85	Sell	Sell	38.00	38.00	2.80	2.80	2.86	2.86	2.95	2.95
TECO Energy	TE.N	18.16	Neutral	Neutral	17.00	17.00	**1.02**	1.01	**1.11**	1.10	1.18	1.18
Westar Energy	WR.N	35.33	Buy	Buy	39.00	39.00	2.38	2.38	2.45	2.45	2.56	2.56
Wisconsin Energy	WEC.N	46.23	Neutral	Neutral	44.00	44.00	2.63	2.63	**2.66**	2.68	**2.76**	2.78
Xcel Energy Inc.	XEL.N	31.76	Neutral	Neutral	30.00	30.00	1.98	1.98	2.09	2.09	2.19	2.19

Source: UBS Estimates *EBITDA

Figure 2: 3Q14 Earnings Center: UBSe vs Consensus

BENCHMARKS	Ticker	3Q14 Earnings Center		
S&P500	SPY	0.0%	3Q14 Performance	
Utilities Select SPDR	XLU	-3.9%	3Q14 Performance	

COMPETITIVE INTEGRATED	Ticker	UBSe	Consensus	Expected Beat/(Miss)
American Electric Power, Inc.	AEP	$1.00	$1.05	-5%
Dominion Resources	D	$0.89	$0.98	-9%
Entergy Corp.	ETR	$2.09	$2.11	-1%
Exelon Corp.	EXC	$0.71	$0.72	-2%
FirstEnergy Corp.	FE	$0.87	$0.93	-7%
NextEra Energy	NEE	$1.48	$1.58	-7%
PPL Corporation	PPL	$0.55	$0.54	1%
Public Service Enterprise Group	PEG	$0.72	$0.77	-7%
Sempra Energy	SRE	$1.22	$1.11	10%
Average				-2.3%

REGULATED INTEGRATED UTILITIES	Ticker	UBSe	Consensus	Expected Beat/(Miss)
Ameren Corp.	AEE	$1.26	$1.28	-1%
Alliant Energy Corp.	LNT	N/A	$1.42	N/A
Avista Corp	AVA	$0.24	$0.24	-2%
CMS Energy	CMS	N/A	$0.44	N/A
DTE Energy Co.	DTE	$1.10	$1.13	-3%
Duke Energy	DUK	$1.59	$1.55	3%
Edison International	EIX	$1.38	$1.32	5%
Empire District Electric Company	EDE	$0.49	$0.43	15%
Great Plains Energy	GXP	N/A	$1.00	N/A
Hawaiian Electric Industries	HE	N/A	$0.47	N/A
PG&E Corporation	PCG	$1.09	$1.09	0%
Pinnacle West Capital Co.	PNW	$2.11	$2.19	-4%
PNM Resources Inc.	PNM	N/A	$0.66	N/A
SCANA Corp.	SCG	$0.97	$1.00	-3%
Southern Company	SO	$1.08	$1.07	1%
TECO Energy Inc.	TE	$0.33	$0.33	1%
Westar Energy, Inc.	WR	$1.07	$1.08	-1%
Wisconsin Energy Corp.	WEC	$0.51	$0.54	-5%
Xcel Energy Inc.	XEL	$0.75	$0.80	-6%
Average				0.0%

REGULATED T&D UTILITIES	Ticker	UBSe	Consensus	Expected Beat/(Miss)
Consolidated Edison	ED	$1.43	$1.40	2%
ITC Holdings Corp	ITC	$0.45	$0.47	-3%
Northeast Utilities	NU	$0.73	$0.76	-5%
PEPCO Holdings Inc.	POM	N/A	$0.45	N/A
Average				-1.9%

INDEPENDENT POWER PRODUCERS	Ticker	UBSe	Consensus	Expected Beat/(Miss)
AES Corporation	AES	$0.34	$0.33	5%
Calpine Corporation	CPN	$747	$730	2%
Dynegy, Inc.	DYN	$140	$110	27%
NRG Energy Inc.	NRG	$973	$1,048	-7%
Average				6.8%

YIELDCOs	Ticker	UBSe	Consensus	Expected Beat/(Miss)
Abengoa Yield PLC	ABY	N/A	$64	N/A
Hannon Armstrong Sustainable Infrast.	HASI	$0.26	N/A	N/A
Pattern Energy Group A	PEGI	N/A	$62	N/A
Tranaslta Renewables	RNW-CA	N/A	$34	N/A
TerraForm Power	TERP	N/A	$45	N/A
NextEra Energy Partners, LP	NEP	N/A	$60	N/A
NRG Yield Inc.	NYLD	$123	$151	-18%
Average				-18.3%

Source: Company Filings, FactSet, and UBS estimates

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3Q Earnings Cheat Sheet

We include call times, dial-in information below.

Figure 3: 3Q Earnings Summary

Company	Ticker	Earnings Release	Conf Call Date	Phone Number & Passcode
AES Corporation	AES	11/06/2014 Unspecified	11/06/2014 9:00 AM	Dial In:877-201-0168, Passcode 14719881
Ameren Corp.	AEE	11/06/2014 Unspecified	11/06/2014 Unspecified	N/A
American Electric Power, Inc.	AEP	10/23/2014 Unspecified	10/23/2014 9:00	N/A
Avista Corp	AVA	11/05/2014 7:05 AM	11/05/2014 10:30 AM	Dial In:(800) 708-4539, Passcode 38233728
Calpine Corporation	CPN	11/06/2014 Before Market	11/06/2014 10:00 AM	Dial In:800 447-0521, Passcode 38036868
Consolidated Edison	ED	11/03/2014 Unspecified	N/A	N/A
Dominion Resources	D	10/31/2014 Unspecified	N/A	N/A
DTE Energy Co.	DTE	10/24/2014 Before Market	10/24/2014 9:00 AM	Dial In:(888) 778-8913, Passcode 8660012
Duke Energy	DUK	11/05/2014 Before Market	11/05/2014 10:00 AM	Dial In:888-471-3820, Passcode 8226680
Dynegy, Inc.	DYN	11/06/2014 Unspecified	N/A	N/A
Edison International	EIX	10/28/2014 Unspecified	10/28/2014 5:00 PM	Dial In:800-369-2198, Passcode Edison
Empire District Electric Company	EDE	10/30/2014 Unspecified	10/31/2014 1:00 PM	Dial In:877-407-5795, Passcode
Entergy Corp.	ETR	11/04/2014 Unspecified	11/04/2014 11:00 AM	Dial In:719-325-2115, Passcode 6761108
Exelon Corp.	EXC	10/29/2014 Unspecified	10/29/2014 11:00 AM	Dial In:800-690-3108, Passcode 15202536
FirstEnergy Corp.	FE	11/04/2014 Unspecified	N/A	N/A
Hannon Armstrong Sustainable Infrast	HASI	11/06/2014 Unspecified	N/A	N/A
ITC Holdings Corp	ITC	10/29/2014 Unspecified	N/A	N/A
NextEra Energy	NEE	10/31/2014 Unspecified	N/A	N/A
NextEra Energy Partners LP	NEP	NA	N/A	N/A
Northeast Utilities	NU	10/30/2014 Unspecified	N/A	N/A
NRG Energy Inc.	NRG	11/06/2014 Unspecified	N/A	N/A
NRG Yield	NYLD	11/11/2014 Unspecified	N/A	N/A
PG&E Corporation	PCG	10/28/2014 Unspecified	10/28/2014 11:00 AM	N/A
Pinnacle West Capital Co.	PNW	10/31/2014 Before Market	10/31/2014 12:00 PM	Dial In:(877) 407-8035
PPL Corporation	PPL	10/30/2014 Unspecified	N/A	N/A
Public Service Enterprise Group	PEG	10/30/2014 Specific Time	10/30/2014 11:00 AM	Dial In:877-370-7635, Passcode 11990191
SCANA Corp.	SCG	10/30/2014 Before Market	10/30/2014 1:00 PM	Dial In:888-347-3258
Sempra Energy	SRE	11/04/2014 Unspecified	N/A	N/A
Southern Company	SO	10/29/2014 Before Market	10/29/2014 1:00 PM	N/A
TECO Energy Inc.	TE	10/31/2014 Before Market	10/31/2014 9:00 AM	Dial In: 877-427-4548, Passcode 14731173
Westar Energy, Inc.	WR	10/31/2014 Unspecified	N/A	N/A
Wisconsin Energy Corp.	WEC	10/29/2014 Specific Time	10/29/2014 2:00 PM	Dial In:866-439-9410, Passcode 16970782
Xcel Energy Inc.	XEL	10/30/2014 Before Market	10/30/2014 10:00 AM	Dial In:888-205-6702, Passcode 2735251

Source: FactSet and Company reports

The PM's View of 3Q Utility Results

AES Corp: *Despite quarterly beat, we are still at bottom-end of FY14 guidance range. Shares are looking more attractive at ~$13.20 but we remain on the sidelines.*

Ameren: *IRP and Clean Power Plan could allow AEE to accelerate spending but even pushed forward capex still likely outside of earnings horizon.*

American Electric Power: *Expect solid update at EEI as 2015/16 guidance raised, alongside potential balance sheet deployment and genco MtM. 3Q could be shy.*

Avista: *Nickel beat on ERM; 2015 initial guidance probably below consensus*

Calpine: *Quarter could be a modest positive, but (further) balance sheet deployment remains the key wildcard given cash. Story getting more traction as a pure-play on PJM capacity reforms given more limited basis risk.*

ConEd: *Signs continue to point towards more certainty for ED in '15 but key datapoint timelines frustratingly lack visibility. Hope springs eternal after the election, with upside on '14 guidance as well.*

Dominion: *Focus is really on Feb Analyst Day, with a 3Q miss likely coupled with capex upside on midstream segment following updates in September. Forward estimates should continue to rise on improving MtM.*

DTE: *In-line 3Q leaves updates around Nexus midstream project – and broader capex amidst focus on Michigan resource adequacy as chief issues.*

Duke: *Tracking towards high end of 2014 guidance, with 3Q updates and results a positive tailwind. Focus also on widening of strategic focus as continue EPS momentum, as well as clues around international re-think.*

Dynegy: *With the ECP/DUK public financing secured, capital market risk is addressed, leaving shares as the cheapest exposure to PJM upside (among other markets).*

Edison International: *Looking for a good update, with $0.10 beat, with upside as look to long-term spend. The soft spot remains risk of PCG spill-over at CPUC.*

Empire District: *In the continued absence of rate relief, wildcard is how significant the oscillating weather will impact results; we expect a beat.*

Entergy: *We look for an in-line pre-release. We believe EEI will be meaningfully quieter than usual given lack of explicit EPS guidance, but we think specific thiexpectations on 2015 sales growth (likely disclosed driver) along with capex. MtM on power should be positive, but likely a topping out.*

Exelon: *Quarter could be above guidance range and FY14 expectations could be lifted as well. ExGen MTM shows reversal of some Summer losses but still down $50/$100Mn on '15/'16 since 6/30 GM guidance. We're constructive.*

FirstEnergy: *3Q looks weak, with ongoing concerns around NJ, WVa and PA rate cases remaining the clearest focus. Don't expect much from FES EBITDA guidance either at EEI for 2016, with further guidance disclosures tabled until 4Q.*

ITC: *Standard quarter with possibility of slight '14 guidance bump; question*

revolves around capex updates more than anything in the near term.

NextEra Energy: *Gubernatorial election in Florida and dime miss on poor wind in 3Q could prove a bottom in shares; we think this is increasingly key opportunity to own a long-term top pick; expect new presentation of NEP metrics with higher growth rate embedded (15-18%?)*

Northeast Utilities: *Nickel miss on mild weather and a slightly higher tax rate – with little to show on Northern Pass. Offsets could (hopefully) include mgmt re-directing corporate attention to other transmission efforts – and gas involvement.*

NRG Energy: *Even with pickup from Alta Wind consolidated EBITDA we estimate ~flat EBITDA guidance for 2015E. Look for management to shift focus to capital deployment (buyback even?) and solar DG strategy.*

NRG Yield: *Enhanced clarity on the rooftop solar strategy and likely announcing pricing/timing on the Walnut Creek*

PG&E Corp: *In-line outcome with unusual 3Q impact from GRC rate increase. Datapoints remain around the GT&S case and San Bruno spillover.*

Pinnacle West: *A nickel miss on mild weather. Expect a positive discussion on the new ACC makeup, some caution on continued strong rooftop solar adoption rates, and constructive commentary on the net metering procedural docket. Also expect to hear more about load growth YTD and expectations.*

PPL: *Despite a potentially weak qtr vs. Street, we see clarification of its EPS growth rate to 4-6% as an offsetting factor – and positive factor into results*

PSEG: *Quarter could be light, but '14 overall looks good. PJM reforms are broadly should lead to general positive halo.*

SCANA: *Slight 3Q miss $0.97 vs consensus $1.00; VC Summer concerns dominate as we await a new schedule from the consortium and SCANA prepares to negotiate costs prior to a special BLRA filing. Generally worrisome.*

Sempra: *We look for a relatively in-line quarter. See upside to estimates from updates on both REX expansion and Cameron 4/5 expansion. Also looking for more insight into management thinking regarding its Yieldco vs MLP debate.*

Southern Company: *Expect an in-line quarter slightly above guidance; more focus on Kemper, Vogtle cost and schedule issues. Also expect an update for economic and load growth throughout its territory.*

TECO: *3Q weighted down by NMGC acquisition although expect to see slightly higher forward EPS estimates as Street integrates deal accretion of ~$0.02*

Westar Energy: *In-line quarter; not likely to give 2015 guidance due to next year's ratecase. Expect more on SPP to prove positive, but ROE pressures abound are the limiting factor on the stock.*

Wisconsin Energy: *Quarter should still come in ahead of guidance despite the cold. Aside from more color on TEG progress, look for more details on ATC and potential standalone growth avenues.*

Xcel: *Weak on Nickel miss on mild weather, and 2015 guidance pushed to EEI. Resolution on cases into year is a defensive attribute.*

Figure 4: Notable 3Q Earnings Beats/Misses by Sub-sector

Notable Beats and Misses	
Competitive Integrated	
9.9%	Sempra Energy
-9.3%	Dominion Resources
Regulated Integrated	
15.4%	Empire District Electric Company
-6.5%	Xcel Energy Inc.
Transmission & Distribution	
2.1%	Consolidated Edison
-4.7%	Northeast Utilities
Independent Power Producer	
27.3%	Dynegy, Inc.
-7.1%	NRG Energy Inc.

Source: Company Filings, FactSet, and UBS estimates

3Q14 Themes

(1) Regulated utilities are the new gold standard: We see several opportunities as standing out amidst the regulated 'safety trade'. Broadly, we continue to see the two best regulated opportunities as PNW and DUK. Even defensive Buy-rated names like ITC have under-performed and appear increasingly attractive amidst the rally (particularly relative to NU of late).

Could diversified utilities be the near term way to play power? If the bias is for a more defensive play, we bias towards PEG and EXC. PPL could yet participate amidst a clarification of its EPS growth rate (4-6%) and guidance revision upwards. While DYN fits the bill the best for power, the diversified utilities may prove the more palatable approach.

(2) Capacity Market Reforms are real – believe it. Many investors continue to discount this theme, claiming they've 'seen it before'. While we appreciate many are tired of 'crying wolf' over capacity price improvements, PJM is appears to be including everything and the 'kitchen sink' in its filing before FERC as part of its comprehensive 'polar vortex' reforms.

(3) YieldCo's are not without their risk: Just as their capital market activity enables these companies to grow beyond their organic capabilities, we see risk to the YieldCo thesis in a challenging capital market environment. Investors should expect volatility here; we think YieldCo's should more appropriately be labelled GrowthCo's with corresponding risk profiles.

But YieldCo's could yet have a good quarterly update. We believe NYLD will announce further drop downs and NEP will raise its growth rate, potentially catching a bid for the sector. The question is if investors will care.

(4) Heat Rates: With 2015 heat rates up 20% in the quarter for 2015 delivery in PJM, we emphasize that power prices have proven resilient despite continued regional gas basis pressures. We think much of this improvement in heat rates remains tied to continued winter uplift.

(5) Should backwardation be the new expectation in power? On the back of accelerating new build expectations, we believe the question of whether backwardation in power is appropriate will largely migrate to a wider acknowledgement that more supply is on the come – with pressure on

forward curves. Meanwhile, we think contango in regional gas basis appears the primary driver for the sharp backwardation in power.

(6) **But what about the risk premium this winter?** We see this as the single biggest risk to power (and gas) in coming months – as the winter premium for delivery could yet face. Specifically, we believe a normalization of weather expectations could yet bring down expectations for Jan/Feb as delivery approaches.

(7) **Announcing new build? The question is are we at new entrant economics.** We think we're about there in PJM, but also see signs suggesting we're approaching those levels in Texas and even New England as well. The right combination of cheap gas, low interest rates, and seemingly declining all-in capital costs (at least heat rate adjusted) continue to surprise investors. We flag even large generators are poised to expand, with EXC in Texas announcing two 1GW CCGTs, and PSEG in new England announcing a 450 MW CCGT at its Bridgeport site.

(8) **Is Oil a new 'bad word'?** We believe pressure to continue across the sector for equities exposed to oil or oil-*linked* products, including Sempra, as it seeks to sign new contracts for its LNG exports in coming months. We emphasize the spread vs. oil remains in place, even under compressed economics. As we illustrated in our latest Sempra note, the return profile remains attractive for development; the question would appear to us *at what price* rather *if* more projects materialize.

What are our top picks?

We include a brief Investment Thesis on each story below.

While 2Q results could be a bit weak, capex update should be constructive into September update

(1) **Dynegy:** We see this name as trading at among the most depressed multiples in the entire sector, at an implied ~6.6x EV/EBITDA 2015, or 7.3x off 2016. Given the litany of positive potential power catalysts, this appears to present the best value in the sector, seeing the potential for shares to trade up meaningfully in months ahead as reforms are executed. Shares should shift away from M&A (and capital market overhangs) towards fundamental catalysts - providing a key shift away from tactical risk in recent weeks. We emphasize the stock remains the best positioned to access upside in each of the following markets, PJM, MISO, and New England.

(2) **NextEra:** We see the latest compression in shares as due in part to both concerns around the upcoming gubernatorial election in Florida as well as deflating YieldCo expectations. However, with this as a backdrop, we see upcoming guidance updates; we believe renewable assets have likely re-rated to a higher, low double-digits EV/EBITDA range (supporting valuations in this neighborhood).

(3) **Dominion:** With further project updates ahead, we believe near-term pressures may translate to eventual opportunity into 4Q results. We think the sum total of data points are likely to lead to a revisiting of the EPS growth rate above the 5-6% level up to a range of 6-8%. Overall, with shares under-performing the Utility sector YTD, shares appear to provide improving 'value' versus peers despite their premium multiple. We emphasize its gas midstream business will eventually force a multiple re-rating away from conventional P/E approaches towards EV/EBITDA.

Best Ways to Play 3Q Themes?

We see the following as particularly noteworthy:

For Duke every $10/barrel change in Brent crude for a full year impacts EPS by ~$0.02.

(1) **We are also highlighting DUK going into 3Q earnings and EEI**, with the company likely reporting a nickel beat on weather and tracking toward the high end of 2014 guidance. We don't expect DUK to initiate 2015 guidance until the 4Q call in Feb 2015, nor do we expect any major incremental updates on the 3Q call or at EEI. However, we do expect the story to continue gelling for investors as a steady large-cap regulated name with substantial growth opportunities on many fronts, including over $20B of growth capex plans covering everything from new conventional gas generation in Florida to commercial renewable solar and wind in both Carolinas (ratebase and merchant), a major stake in the $5B Atlantic Coast Pipeline project, $3B of environmental and nuclear compliance, $3B-$5B of new transmission spending, and the $1.2B purchase of North Carolina Eastern Municipal Power Agency's (NCEMPA) minority ownership in ~700 MW of existing Duke Energy progress nuclear and scrubbed coal plants. Furthermore, the company now has legislation in place in North Carolina to invest in coal ash remediation, an opportunity that could be worth $2B-$10B over the next 10 years. Then there's also the sale of the merchant fleet to DYN to close and the strategic review of International to finalize by yearend. Last but not least, management is keenly observing the outcome of NEE's small gas ratebase pilot program, although this potentially important opportunity is not yet being actively considered by the company.

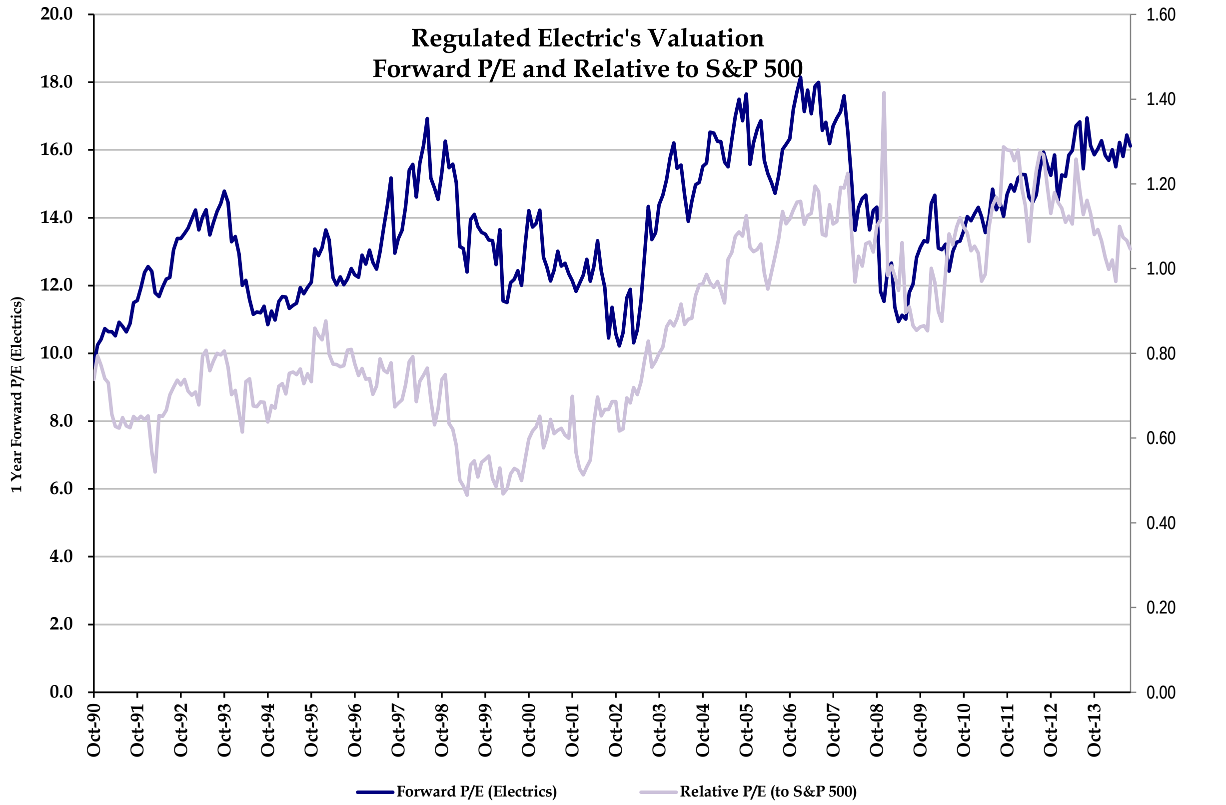
(2) **We highlight AEP going into 3Q earnings and EEI**, when management is expected to increase its 2015/16 guidance for higher commodity pricing as well as O&M shifting into this year. We also look for a positive revision to long-term earnings growth guidance as we continue to believe that AEP will have no trouble in 2014 meeting or even exceeding its 4-6% growth target off a base of original 2013 guidance $3.05-$3.25. With full-year 2013 operating EPS of $3.23, management has set a readily achievable earnings target as it is starting its trajectory nearly $0.10 above this EPS midpoint and the midpoint of 2014 guidance ($3.45 vs UBSe and consensus $3.48) is equal to the high-end implied by its 4-6% long-term growth rate indicating that even with no additional earnings in 2015 or 2016 it will be within its target range. Furthermore, AEP has several positive catalysts to look forward to over the next 6 months, including the completion of asset transfers (Amos and Mitchell), the approval of the Ohio ESP rate plan after elections, including the possible approval of a PPA for its merchant fleet (especially the OVEC assets), and the possible sale of its GenCo merchant fleet in the next 6-2 months. Additionally, there could be possible improvement in ratebase recovery for Turk in Arkansas after elections and the possibility of increasing leverage at the independent Transmission Company, which could boost EPS by up to $0.15 without undue stress on the balance sheet.

Market Volatility Pushing Large Cap Regulated Utilities Higher

In recent months, we've seen a significant heightening of market beta volatility as well as intra-sector correlation that appear to be following the usual "risk off" pattern that has repeated itself many times since the Great Recession of 2008. In our view, names that have tended to benefit in such flights to safety include large-cap regulateds such as ED, DUK, SO, and XEL; and we would add AEP and EIX to that list now too. While PCG would normally fit the profile as well, we think the continued regulatory and political controversy surrounding San Bruno and most recently the ex-parte revelations justifiably keep the stock from being considered "safe". Among the mid-cap names, we usually see WEC and NU outperform during turbulence as well. With the S&P 500 down over 6% off its Sept highs and XLU flattish (although up over 5% in the past week), we would view this recent period as more of a temporary correction triggered by a confluence of world events including strife in the Middle east, worries over Asian economies, disease, and the usual October malaise.

Defining what is truly a large cap defensive utility is elusive and remains the opportunity.

Figure 5: US Utilities Relative to the Market on Forward Year Basis



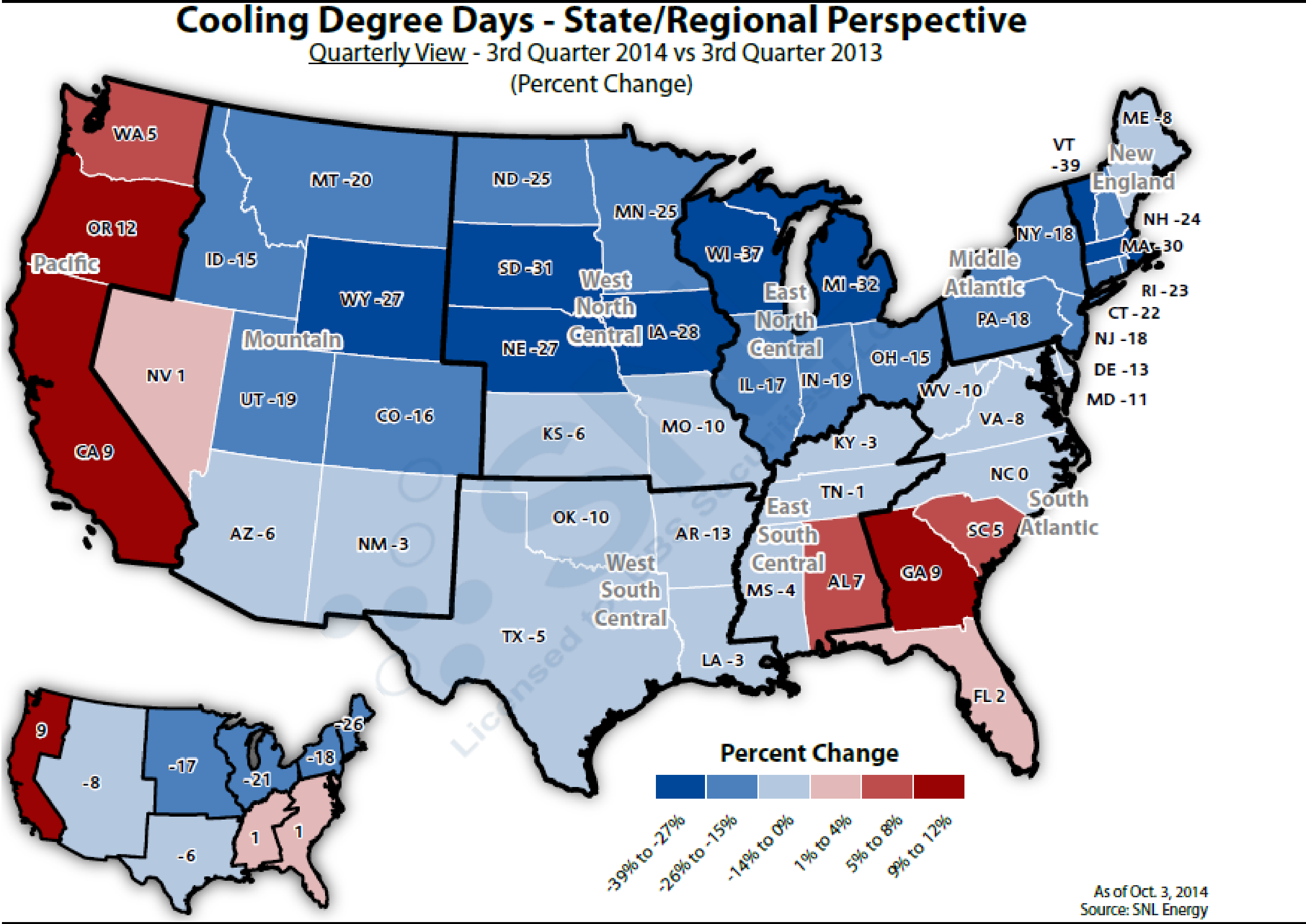
Source: FactSet

So how cold was the Summer weather?

Below we present the third quarter cooling degree days (CDDs); however that does not tell the entire story as there was extreme temperature month-by-month. In July the country had unseasonably mild temperature outside of the Pacific Northwest for the most part with the North Central and Mid Atlantic seeing over a 30% decline in CDDs. In August the middle of the country and the South rebounded to

see modest increases in CDDs while the Mountain region felt the grip of cold temperature. September brought the return of heat in the Northeast and Pacific (minus Washington) but the central and Texas remained well below average. Overall Wisconsin and Michigan exposed utilities include WEC, DTE, and CMS could see much of their 1Q14 weather uplift thawing.

Figure 6: Unseasonably cool summer across most of the country sets low expectations for the quarter



Source: SNL

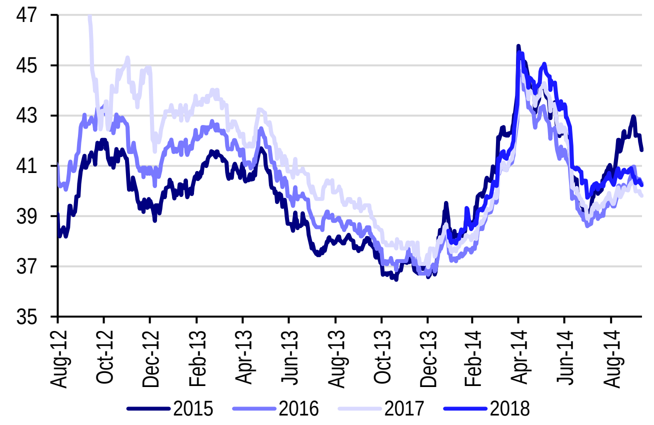
Commodity Views on PJM

Below we present the latest PJM power forwards and heat rates. We note prices have recovered in 3Q, after the pullback following the early year rally. They have however ticked downwards again in recent weeks. We note a backwardation in the PJM market with 2017 heat rates significantly below 2015/16 (all of which however have been rising since July).

The Power Move of Late: Heat Rate

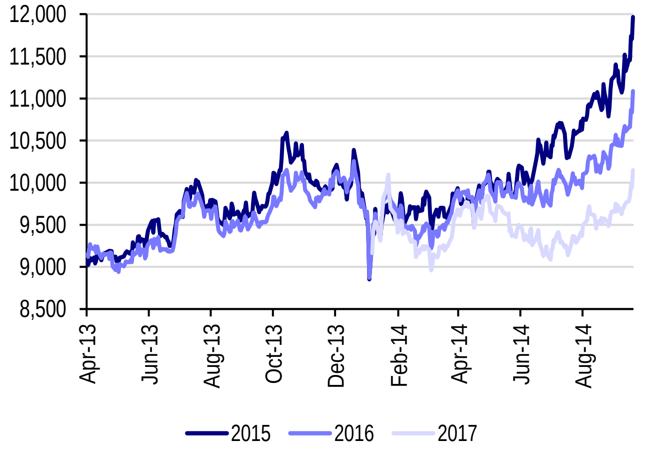
At current heat rates across the PJM footprint, well north of what we've seen before, we see the argument for new entry of gas plants as only further bolstered.

Figure 7: PJM West ATC Prices



Source: Platts and UBS estimates

Figure 8: PJM West ATC Heat Rates

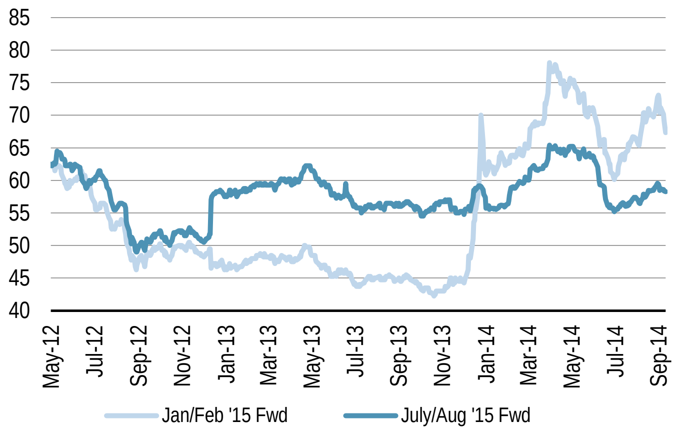


Source: Platts and UBS estimates

Seasonal trade: <u>winter</u> still driving the ship in PJM – and intact into winter

Winter premium is **back** for PJM; is that just a risk premium waiting to go away? We're a bit more bearish on the 2015 curve as winter weather expectations 'normalize' YoY. We emphasize summer forward delivery remains below winter prices, with expectations remaining largely flat vs. year ago levels.

Figure 9: PJM Seasonal Forward Curves ($/MWh)

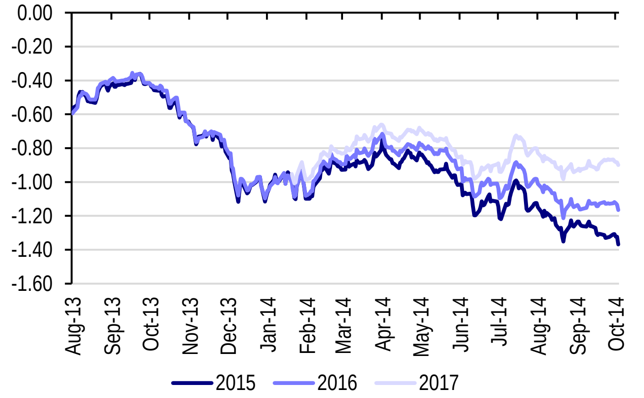


Source: Platts and UBS estimates

What about Gas Basis for PJM? Continues to weaken

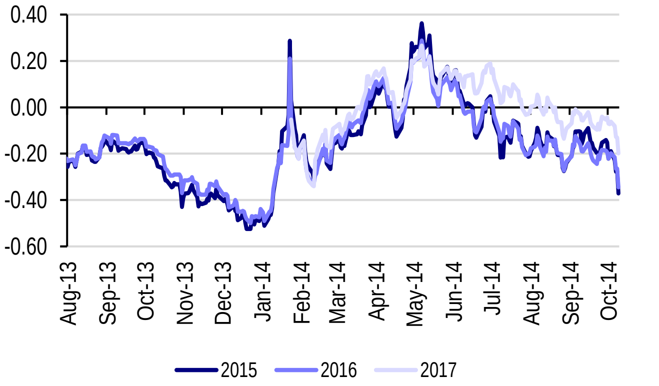
Below we show Dominion-South and TETCO M3 basis. Gas basis Dominion-South declined early on in 3Q, but generally flattened out in the latter half. However, TETCO M3 basis continued with a declining trend over the entire quarter.

Figure 10: Dominion-South Gas Basis ($/MMBtu)



Source: Platts

Figure 11: TETCO M3 ($/MMBtu)



Source: Platts

And what about Capacity reforms?

We include a snapshot of our latest views on the capacity reforms below. While we expect this process to yet unfold in the coming days and weeks ahead as PJM files and FERC, and with a subsequent decision from FERC in early 2015. We see the reforms overall as driving the fundamental upside in the market.

Figure 12: Potential clearing price PJM in 2018/19

Potential clearing price 2018/19			
Impact from new rules	GW - $ sensitivity		~$/MW-Day impact
DR	7.7	8	62
CP	-	-	100
Holdback	4.1	8	33
Demand curve	-	-	10
Incremenal supply	10	(8)	-80
~ Total $/MW-Day Impact (A)	-	-	**124**
Clearing Price in 2017/18 $/MW-Day (B)			120
Potential clearing price 2018/19 (A+B)			**244**

Source: PJM, UBS estimates

Explaining the Drivers of our Positive PJM View on Capacity Prices:

(1) Demand Response likely to decline significantly: Our latest call pinned the total amount of DR clearing under eligible constructs (through Load Serving Entities) at ~30% of existing commitments, suggesting 70% of the 11GW currently committed into the auction as unwinding in the most dramatic example. While we believe state PSCs and legislators are likely to rapidly implement programs to 'force' utiletlies to sign more commitments– enabling a manner in which EnerNOC and other aggregators can continue to

sell their products to utilities. Regardless, we think the bulk of this 70% will initially be in some doubt, putting ~$60/MW-day upside assuming the $8/MW-day sensitivity to RTO prices for a 1GW decline in commitments

(2) **Capacity Performance scheme itself likely to drive up prices significantly.** We continue to see prices from this scheme as conservatively edging up cleared prices by $100/MW-day, with the latest proposals pinning the requirement for the CP product at ~80% of all capacity.

We emphasize from a 'market mitigation' perspective, we believe the requirement will be framed as the market needs a maximum of 20% base capacity, with generators likely to attempt to keep their resources under this lower commitment in an effort to bolster pricing for the new CP product (effectively arbitraging the portfolio uplift between the two new products).

(3) **Removing the 2.5% Holdback:** 'When it rains it pours': We see PJM's decision to reverse its course on this policy (following a long-standing back-and-forth with the market monitor), further drives ~$30/MW-day upside to the market, seeing 2.5% as equivalent to adding ~4GW of demand back into the market.

(4) **Demand curve uplift under the triennial review:** The latest demand curves, already proposed before FERC could yet drive at least $10/MW-day, if not up to $50/MW-day upside to market prices in specific constrained areas. The latest curve effectively pushes out the reserve procurement by +2%, enabling higher prices under scenarios of higher reserve margins.

Sensitivities to the Upside: Meaningful

Below, we show the sensitivities for stocks exposed to the PJM footprint for a ~$125/MW-Day change in pricing. Dynegy has the second largest sensitivity to price changes in PJM – as high as 43% improvement in EBITDA in this case.

EXC, FE and PSE&G also have high exposure (all above 20% for either EBITDA or EPS); whereas D and NEE have the lowest sensitivity.

We emphasize Dynegy remains the best exposure, followed by Exelon in our view (but note the equity continues to see meaningful energy price exposure to the Mite-Atlantic). For those truly averse to gas basis, we see some interest in owning Calpine around this thesis as well.

Figure 13: Sensitivities to $125/MW-Day Change in Capacity pricing in PJM Interconnect

PJM Capacity Market Upside	PPL (Talen)	DYN	NRG	EXC	FE	PSEG	CPN	NEE	D	AEP	AES	Total
Nameplate Capacity (MW)	12,783	11,940	18,658	22,142	9,477	12,042	4,946	1,029	1,408	8,668	3,198	81,568
EFORd Adj. (MW)	12,052	11,265	17,506	20,794	8,942	11,333	4,663	964	1,228	8,135	2,866	76,430
Clearing Price in 2016/17 $/MW-Day	$ 59.37	$ 59.37	$ 59.37	$ 59.37	$ 59.37	$ 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	$ 120	$ 120	$ 120	$ 120	$ 120	
$125/MW-day Sensitivity ($M)	**547**	**512**	**795**	**944**	**406**	**515**	**212**	**44**	**56**	**369**	**130**	**3,470**
Impact to EPS				**$ 0.71**	**$ 0.63**	**$ 0.66**		**$ 0.06**	**$ 0.06**	**$ 0.49**	**$ 0.12**	
2017 EPS or EBITDA	**$ 733**	**$ 1201**	**$ 2958**	**$ 2.60**	**$ 2.48**	**$ 2.76**	**$ 1893**	**$ 6.94**	**$ 4.67**	**$ 3.88**	**$ 1.56**	
% of total 2017 UBS Estimate	**74.7%**	**42.6%**	**26.9%**	**27.4%**	**25.3%**	**23.9%**	**11.2%**	**0.9%**	**1.3%**	**12.7%**	**7.5%**	

Source: SNL, UBS estimate; estimate for Talen is NOT adjusted for PPL ownership.

Recent PJM notes:

10/10 Framing the PJM Upside
10/8/14 PJM: Ramping Up Compensation, Sooner
9/29/14 Turning the Heat Up on PJM to Perform
9/18/14 In a Tight Spot: The Power Constraints Thesis
9/16/14 PJM's Potential Triple Whammy Uplift
9/5/14 Defining PJM ' Capacity Performance Yields Upside to Constrained Regions (Incl. Conf. Call Transcript)
8/22/14 PJM Attacks the Polar Vortex

PJM Quarterly [Spot] Power Prices

3Q14 basis for PEPCO and BGE remained positive and recorded a sizable increase from 2Q14. However, PSEG, PPL, AD and NI basis continued to be negative zone. Notably, basis for ATSI hub dropped significantly and turned to negative following a small positive basis recorded in 2Q14. The bifurcation between PSEG zone compression and meaningful BGE/PEPCO premiums continued, as Eastern PJM continues to redefine itself.

Eastern PJM continues to break between NJ and MD

Figure 14: Average PJM Regional LMP Prices, by Zone ($/MWH)

Avg LMP Price	2014	3Q14	2Q14	1Q14	2013	4Q13	3Q13	2Q13	1Q13	2012	4Q12	3Q12	2Q12	1Q12	2011	2010	2009	2008
West Hub	**58.60**	**35.78**	41.43	91.63	**38.42**	37.86	39.48	38.80	37.51	**33.89**	35.81	36.15	31.74	31.82	**43.59**	**46.59**	**39.25**	**69.81**
Henry Hub	**4.55**	**4.06**	4.67	4.94	**3.65**	3.60	3.58	4.09	3.34	**2.79**	3.40	2.81	2.22	2.74	**4.04**	**4.39**	**3.99**	**8.99**
Heat Rate	**12.9x**	**8.82**	8.9x	18.6x	**10.5x**	10.5x	11.0x	9.5x	11.2x	**12.1x**	10.5x	12.9x	14.3x	11.6x	**10.8x**	**10.6x**	**9.8x**	**7.8x**
PSEG	**68.32**	**33.82**	41.41	118.40	**41.93**	40.18	41.63	41.15	44.82	**34.76**	38.15	38.12	30.75	31.93	**48.32**	**50.89**	**42.40**	**79.78**
Basis	**9.72**	**(1.96)**	(0.02)	26.77	**3.52**	2.33	2.15	2.35	7.30	**0.86**	2.35	1.98	(0.99)	0.10	**4.72**	**4.30**	**3.14**	**9.96**
PPL	**71.80**	**32.20**	38.56	105.41	**38.01**	37.03	39.60	38.58	36.80	**33.19**	36.51	35.81	29.84	30.53	**45.68**	**47.67**	**40.42**	**74.25**
Basis	**5.40**	**(3.57)**	(2.88)	13.77	**(0.41)**	(0.82)	0.12	(0.22)	(0.72)	**(0.70)**	0.70	(0.34)	(1.90)	(1.30)	**2.09**	**1.08**	**1.17**	**4.44**
PEPCO	**77.34**	**40.05**	44.76	110.28	**41.04**	40.56	41.89	41.23	40.48	**36.05**	37.52	38.29	33.73	34.62	**47.58**	**52.94**	**43.12**	**81.26**
Basis	**10.94**	**4.27**	3.32	18.65	**2.63**	2.70	2.41	2.43	2.97	**2.16**	1.71	2.14	1.99	2.79	**3.99**	**6.36**	**3.86**	**11.45**
BGE	**79.08**	**42.62**	46.54	111.98	**41.53**	40.77	42.73	42.18	40.41	**36.91**	38.35	39.08	34.76	35.40	**48.51**	**53.24**	**43.14**	**80.71**
Basis	**12.69**	**6.85**	5.11	20.35	**3.11**	2.91	3.25	3.38	2.89	**3.02**	2.54	2.93	3.02	3.58	**4.92**	**6.36**	**3.89**	**10.89**
AD Hub	**54.12**	**33.06**	40.32	68.07	**35.01**	34.06	35.55	36.35	34.06	**31.22**	33.13	33.20	29.06	29.46	**38.69**	**37.58**	**33.38**	**53.19**
Basis	**(12.28)**	**(2.71)**	(1.11)	(23.56)	**(3.41)**	(3.80)	(3.93)	(2.45)	(3.45)	**(2.67)**	(2.68)	(2.95)	(2.68)	(2.37)	**(4.91)**	**(9.00)**	**(5.87)**	**(16.63)**
NI Hub	**48.74**	**31.06**	36.63	60.98	**32.20**	30.99	33.50	33.16	31.13	**28.57**	28.51	32.32	26.20	27.20	**33.24**	**33.13**	**29.22**	**50.04**
Basis	**(17.66)**	**(4.71)**	(4.81)	(30.65)	**(6.22)**	(6.87)	(5.98)	(5.64)	(6.38)	**(5.32)**	(7.30)	(3.83)	(5.54)	(4.63)	**(10.35)**	**(13.46)**	**(10.04)**	**(19.77)**
ATSI Hub	**58.06**	**34.18**	41.69	74.61	**36.54**	36.02	37.85	37.31	34.94	**32.11**	34.38	34.65	29.26	30.09	**39.34**			
Basis	**(8.34)**	**(1.60)**	0.26	(17.03)	**(1.88)**	(1.83)	(1.64)	(1.49)	(2.57)	**(1.78)**	(1.43)	(1.50)	(2.48)	(1.73)	**(3.05)**			
AD - NI Hub Basis	5.38	2.00	3.69	7.09	2.81	3.07	2.04	3.19	2.93	2.65	4.62	0.88	2.86	2.26	**5.45**	**4.46**	**4.16**	**3.15**

Source: PJM and UBS estimates

Commodity Views on ERCOT

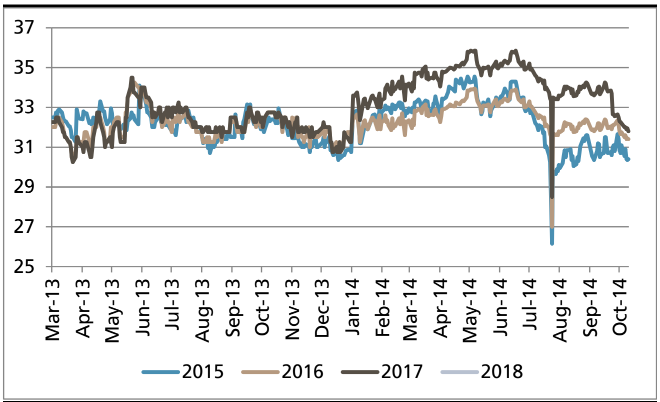
The punchline here remains patience, with uncertainty on when demand will outpace new Supply.

But what about new wind build? This is the latest concern

We remain primarily focused on growing expectations for Texas wind build to reach recent highs at a pace of ~2-3GW/yr, with a total of ~5-6GW projected by mid-2016. We flag that offpeak prices have continued to sag meaningfully, likely on the back of financial hedging of obligations.

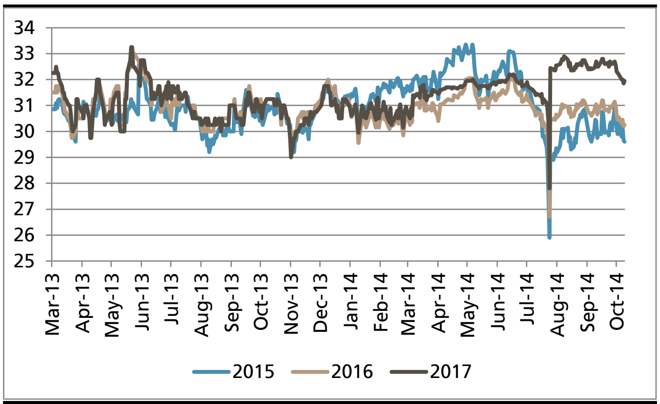
Wind fears continue blow in West Texas – but limited further transmission expansion after CREZ

Figure 15: ERCOT Houston Off-Peak ($/MWh)



Source: Platts and UBS estimates

Figure 16: ERCOT North Off-Peak ($/MWh)



Source: Platts and UBS estimates

What else is the hold up? New gas build -> Both merchant and contracted

We flag EXC's recent decision to pursue 2 new 1GW CCGTs, as well as continued new build efforts by developers like Navasota as indicative of potential 'new entry' economics in this market. While we don't necessarily see the returns as appealing (without a discount to greenfield), we do see at a minimum potential for further brownfield additions, *and* more contracted capacity opportunities with muni's and coop's responsibly for procuring their load

Lastly, the real piece to the puzzle remains demand – and demand response

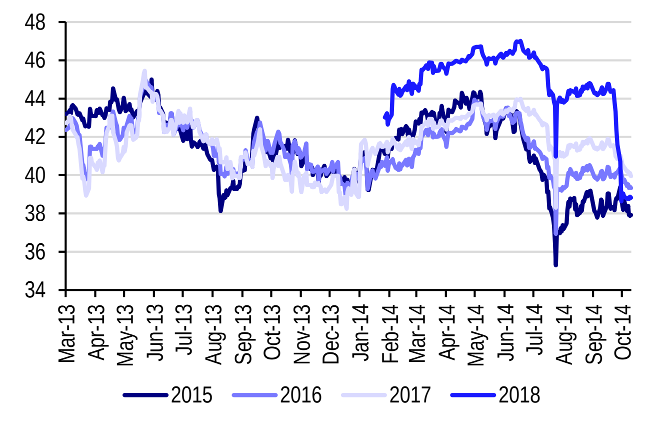
Among the most common factors to the bullish outlook in Texas remains the demand equation. We continue to see significant load growth from both the E&P side of the equation in the Southern and Western parts of the state, alongside continued focus along the Gulf coast with continued industrial activity growth. We think this will be more of a 2016 story, as these sites are long-dated in in-service, and seeing new 2014 supply as largely addressing near term needs.

The big upside remains EPA-driven tightness, eventually?

Offsetting this bearish view of wind, remains our more constructive view of eventual further retirements of coal plants in Texas. Specifically, we look towards Monticello and Martin Lake. We emphasize neither is likely a near term event, but remains a potential as part of restructuring – specifically see the potential for re-implementation of CSAPR coupled with other rules as the triggering factor. Moreover, current off-peak economics in ERCOT-North coupled with more wind could yet drive some coal units off the market. All this is likely to put the pressure

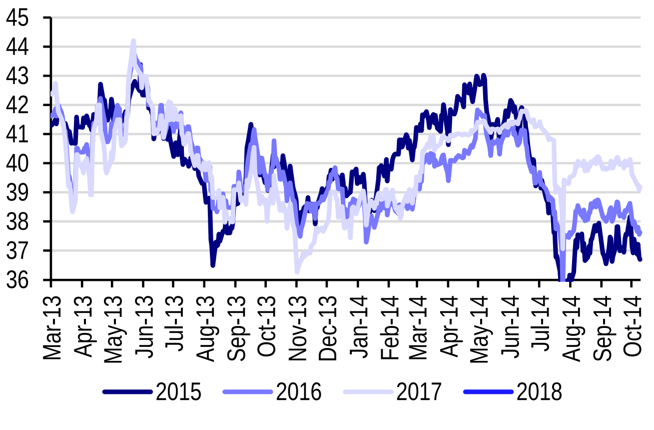
yet again on the PUCT and ERCOT for added regulatory reform through more 'capacity' like compensation.

Figure 17: ERCOT Houston ATC ($/MWh)



Source: Platts and UBS estimates

Figure 18: ERCOT North ATC ($/MWh)

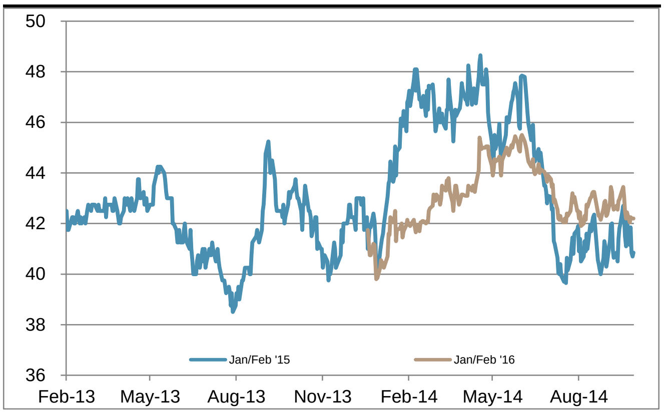


Source: Platts and UBS estimates

Lastly, pricing in the scarcity is the big question?

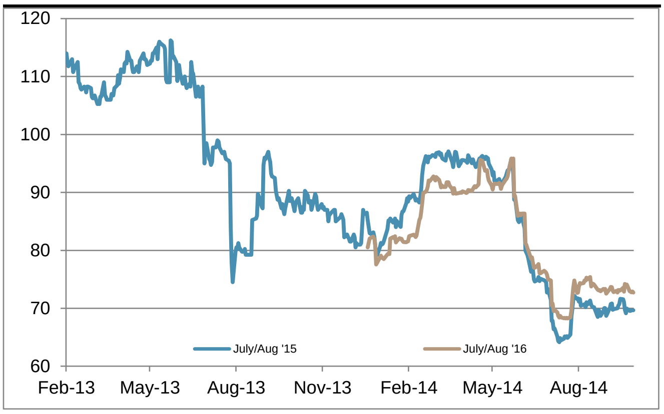
We emphasize that without a meaningful summer in Texas, we have yet to really see the ORDC implementation, with a higher de-facto cap of $9,000/MWh take effect. With prices off meaningfully for Summer delivery for both 2015 and 2016 for the July/August period, we think little in scarcity pricing is being priced in.

Figure 19: Jan/Feb '15 & '16 ERCOT-Houston Forwards – Relatively Resilient



Source: Platts

Figure 20: July/August '15 & '16 ERCOT-Houston Forwards – The Source of Recent Forward Compression



Source: Platts

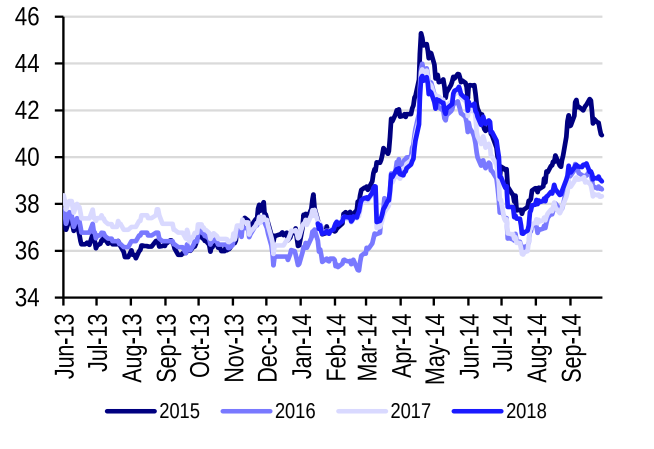
Commodity Views on the Northeast

New York and New England power prices have proven to be among the most resilient, showing the best trends in recent weeks. While not hitting the May highs from earlier this year, we think much of this is due to both the partial retirement of Dunkirk as well as future expectations for nuclear plant retirements in New York – we remain generally cautious on further improvement in this market.

Meanwhile, in New England, we attribute recent recovery on this market to reduced expectations for new gas pipeline development as the Governor's regional NESCOE efforts have broken down. We view delays on moving forward with new projects are likely to be protracted due to twin NIMBY – and contracting issues.

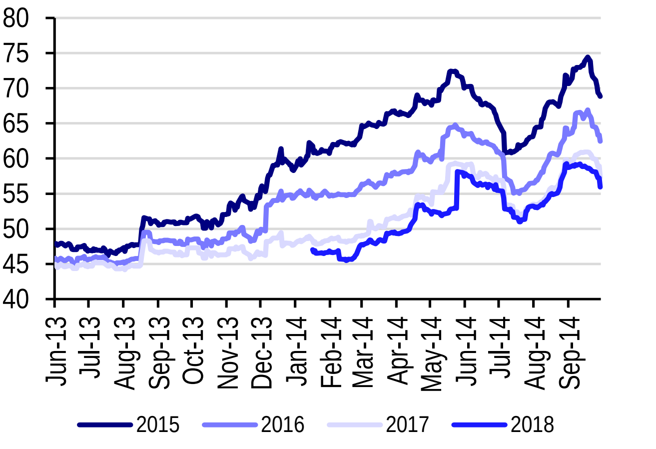
We think new entry in the 2018/19 period (to be cleared in next year's capacity auction) along with future transmission improvements (also long-dated) will prove the limiting factor on improvement.

Figure 21: NYISO Zone A ATC ($/MWh)



Source: Platts and UBS estimates

Figure 22: Mass Hub ATC ($/MWh)



Source: Platts and UBS estimates

We remain constructive on gas basis premiums

Holding up our more constructive view of both capacity and power prices in New England is our view that new pipeline projects will prove protracted, seeing doubt over the success of pending NESCOE initiatives.

New York capacity likely topping out – but how much downside?

Meanwhile we think the NYISO capacity and energy markets are likely topping out, particularly with the re-entry of the Danskammer units into the market (at full ~400 MWs) alongside further units listed below. We see particular downside to LHV prices, particularly with growing focus on downside under further eventual transmission build.

Figure 23: Summary of Recent NY Capacity Announcements

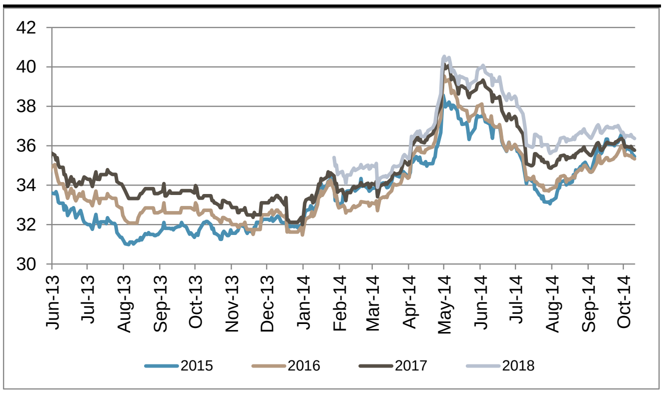
Summary of Recent New York "New Entrants"			
Plant	*MW*	*Time Frame*	*Region*
Danskammer	530	YE14	LHV
Astoria Unit 20	180	Summer '15	NYC
Binghamton Cogen	48	YE14	ROS
Selkirk I & II Cogen	345	Reversed Decision	ROS
Total	**1,103**		

Source: New York Independent System Operator (NYISO) and UBS Estimates; the estimates above are *not* adjusted for EFOR. Danskammer appears to be coming back as 400 MW, vs. its original rating as 530 MW.

Commodity Views on Midwest Markets

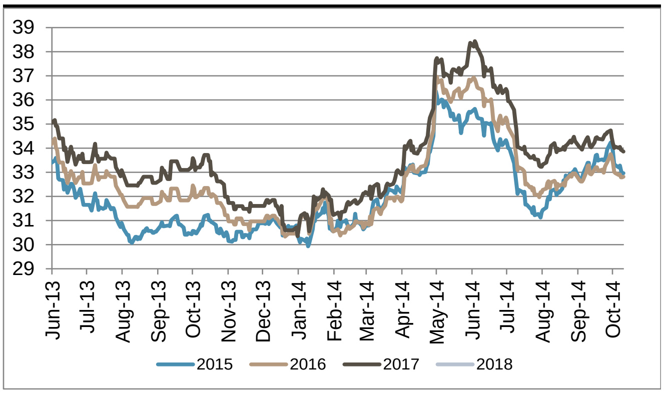
ATC prices at both the Indy Hub and NI Hub have largely round-tripped in the quarter. We remain mixed in our view of the Midwest market. We see the latest winter as having been driven not just by an extremely cold winter, but also factors including rail deliveries and pipeline outages appear to have exacerbated the winter, all of which we consider to be more one-time events.

Figure 24: Indy Hub ATC ($/MWh)



Source: Company reports and UBS estimates

Figure 25: NI Hub ATC ($/MWH)



Source: Company reports and UBS estimates

Capacity market developments in MISO – Generally Good

We see constructive developments in the MISO market of late – net-net, we remain constructive to see continued capacity price increases in subsequent capacity auctions, with continued datapoints indicating pricing on capacity is the $2/kW-mo range, with the best pricing in the Michigan markets.

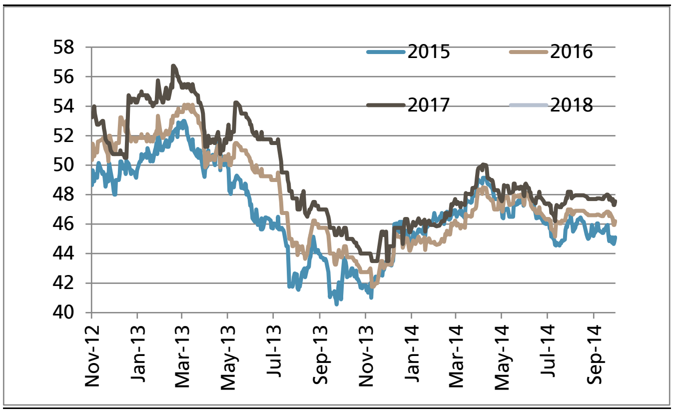
Please see our recent note on MISO Capacity prices here.

Commodity Views on California

Fundamentally, we continue to see meaningful long-term pressures on California forwards as the drought normalizes in future years. We continue to believe that power prices remain elevated vs. fundamental levels largely on account of the drought masking the underlying pressures from continued renewables growth.

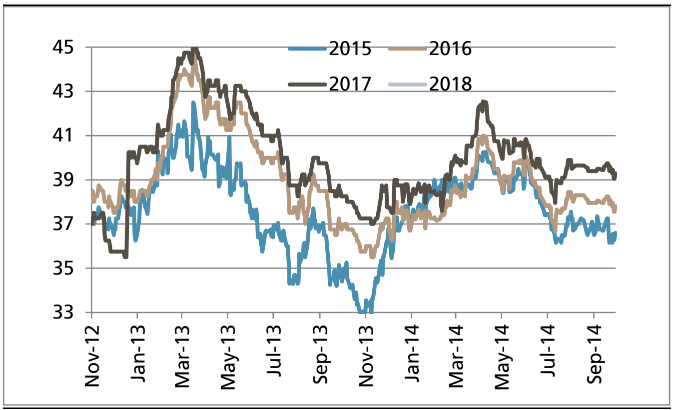
The charts below show evolution of on-peak and off-peak power prices for the NP15 market. Both curves have seen meaningful recovery from their floors seen last winter, and they have risen over the early part of the year as expectations for drought built up.

Figure 26: On-Peak NP15 Prices ($/MWh)



Source: Platts

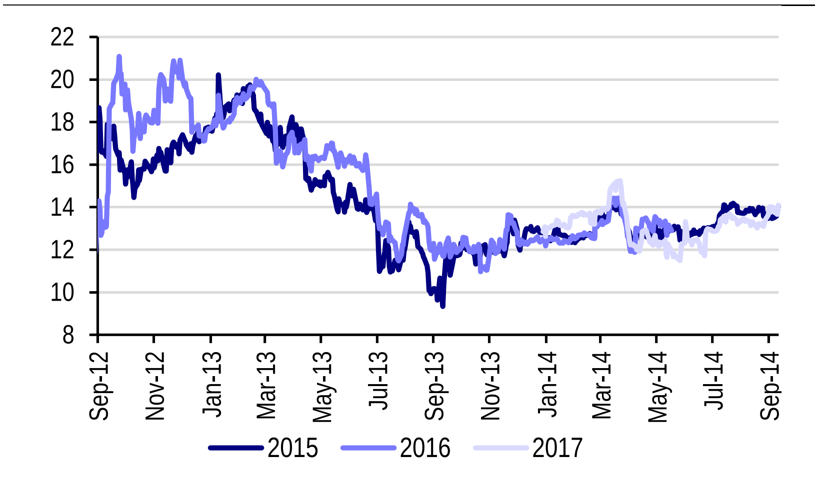
Figure 27: Off-Peak N15 Prices ($/MWh)



Source: Platts

We flag spark spreads have proved relatively intact for much of the last year despite growing expectations for renewable deployment (offsetting drought impacts). Here, we emphasize that sparks are indeed slightly backwardated, with 2017 below 2015.

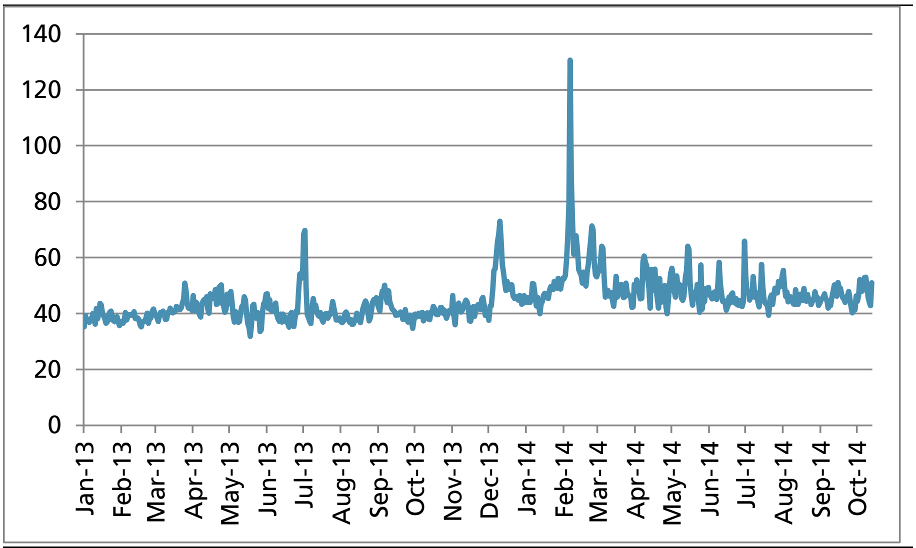
Figure 28: NP15-PG&E Citygate Spark Spread @ 7.2 Heat Rate ($/MWh)



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

Spot prices in 3Q were higher YoY, as higher temperatures were recorded alongside the drought conditions encountered. We believe Calpine may yet report constructive results on the back of a positive surprise in this market.

Figure 29: CAISO North Bay 24 Hour Average Price

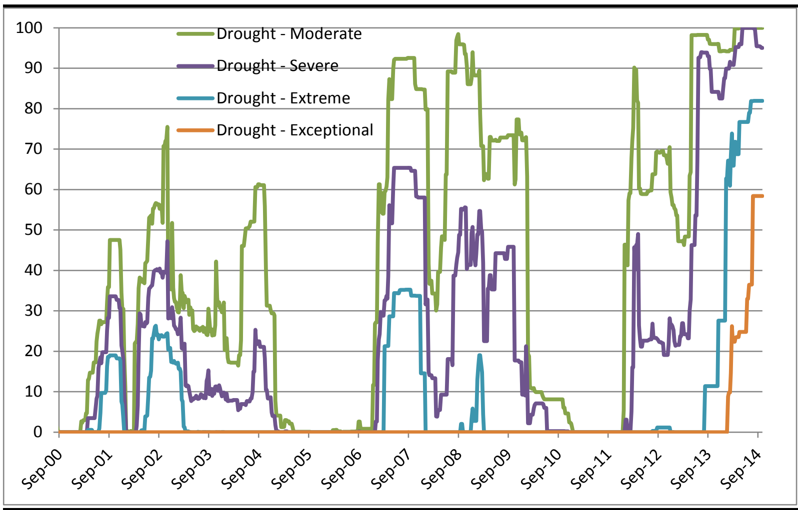


Source: Bloomberg

The drought is masking underlying supply shift we think

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): much worse this time.



Source: NOAA

Latest SCE procurement this week should yield new thermal and storage projects

More thermal plants coming

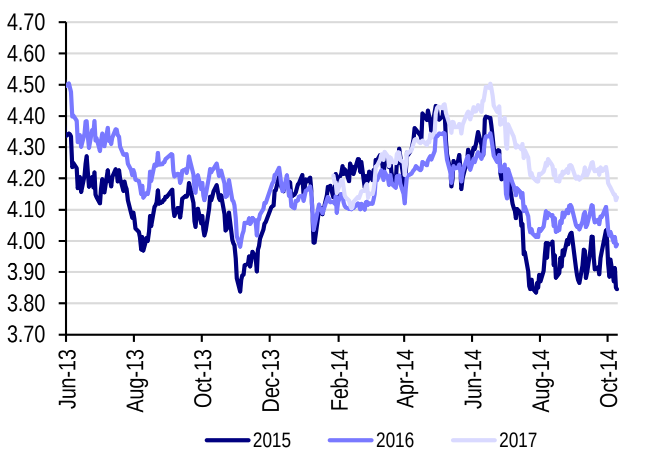
Among the biggest developments in coming days, we look for SCE to announce the results of its RFP – likely awarding at least AES a new thermal plant, if not a storage project. Further we think even CPN could yet see a project award. We understand results are due on Thursday, October 16th, but no later than the 21st.

What's the Latest with Gas Overall?

Henry Hub prices have declined ~$0.50/MMBtu off their highs as weather has failed to materialize this year, enabling a rapid refilling of storage off sharp deficits from last winter. Following a meaningful deficit vs. historic average storage, we continue to project some softness in natural gas prices into 2015 in order to reconcile the energy outlook.

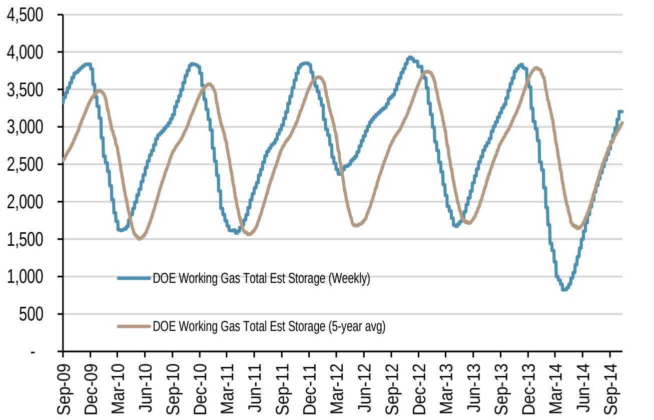
See our latest note on gas production here – and basis expectations for PJM.

Figure 30: Henry Hub NYMEX Gas ($/MMBtu)



Source: Platts

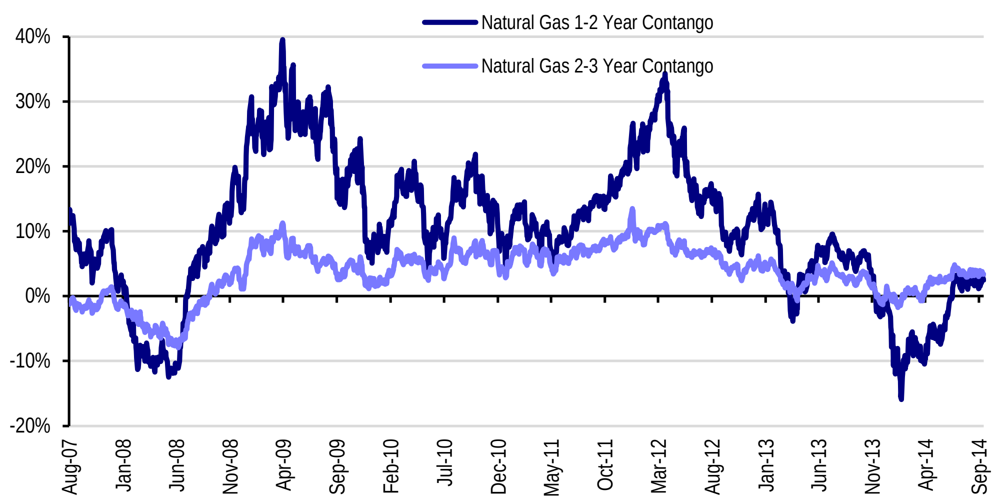
Figure 31: Natural Gas Storage (Bcf)



Source: DOE Data via Bloomberg

Despite a more negative view on gas prices more broadly, the curve appears to have returned to a more 'normal' shape, with a modest amount of contango.

Figure 32: Latest Natural Gas Contango: Approaching Recent Lows from Last Year & 2008



Source: Bloomberg and UBS estimates

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.

Figure 33: Forward ATC Heat Rates (MWh/MMBtu) by Power Market

	2015	2016	2017	2018
NP15 / PG&E	10.32	10.33	10.15	10.17
YoY % Change		0.2%	-1.8%	0.2%
ERCOT-S/Houston Shipping	11.51	11.25	11.00	10.13
YoY % Change		-2.3%	-2.2%	-7.9%
NYISO Zn G / Transco Zn 6	13.60	13.26	12.75	12.31
YoY % Change		-2.5%	-3.9%	-3.4%
Southern / Transco Zn 4	10.31	9.81	9.71	9.55
YoY % Change		-4.9%	-1.0%	-1.7%
Mass Hub / Algonquin	10.24	10.32	10.54	9.98
YoY % Change		0.8%	2.2%	-5.4%
Entergy / Henry Hub	9.68	9.25	8.97	8.67
YoY % Change		-4.4%	-3.0%	-3.3%
NI Hub / Chicago Citygate	10.54	10.38	10.40	10.12
YoY % Change		-1.5%	0.1%	-2.7%
PJM West / TETCO M3	13.92	12.80	11.66	11.26
YoY % Change		-8.0%	-8.9%	-3.4%
AD Hub / MichCon	11.23	11.05	11.05	10.75
YoY % Change		-1.6%	0.0%	-2.7%
ERCOT-Houston/Houston Ship	11.93	11.76	11.51	10.56
YoY % Change		-1.4%	-2.2%	-8.2%
ERCOT-West/Houston Ship	11.25	11.04	10.82	9.95
YoY % Change		-1.8%	-2.0%	-8.0%
ERCOT-North/Houston Ship	11.46	11.17	11.05	10.56
YoY % Change		-2.5%	-1.1%	-4.5%
CIN-Hub/ Chicago Citygate	10.97	10.82	10.79	10.51
YoY % Change		-1.4%	-0.3%	-2.5%
Average		*-2.4%*	*-1.8%*	*-4.1%*

Source: Platts and UBS estimates

Regional Heat Rates: Sharp Shifts by Region

We also include ATC Heat rate change YoY for 2015 forward delivery to illustrate the changes in the last year. ERCOT Heat rates have continued to lag while the Northeast (NYISO upstate and Mass Hub) markets have improved the most. We also emphasize the Midwest markets and PJM appear to have seen substantial improvements in heat rates as regional power prices have continued to decline.

The story in power of late has been heat rate moves

Figure 34: ATC Heat Rates – Change YoY for Forward 2015

ATC Heat Rates 2015						
	ERCOT-North	**ERCOT-Houston**	**ERCOT-West**	**ERCOT-S**	**Entergy**	**Southern**
Oct-14	9,675	10,003	9,486	9,524	8,229	8,976
Oct-13	10,040	10,442	9,911	10,065	7,233	7,936
YoY % Change	-4%	-4%	-4%	-5%	14%	13%
	NY-ZnG	**NY-ZnJ**	**NY-ZnA**	**MassHub**		
Oct-14	11,488	11,994	10,102	8,907		
Oct-13	11,109	11,775	8,669	8,146		
YoY % Change	3%	2%	17%	9%		
	PaloVerde	**SP15**	**NP15**	**MidC**		
Oct-14	9,611	10,656	9,277	8,006		
Oct-13	9,462	10,359	8,820	8,420		
YoY % Change	2%	3%	5%	-5%		
	Indy Hub	**NI Hub**	**ADHub**	**PJM-W**		
Oct-14	8,981	8,331	9,403	11,461		
Oct-13	7,981	7,655	8,684	9,702		
YoY % Change	13%	9%	8%	18%		

Source: Platts/ Bloomberg

Forward Price Moves in The Quarter: Negative.

Marking-to-market models by quarter, we expect positive revisions still for companies like DYN and ETR due to strong New England moves. Meanwhile, EXC should see a modest negative revision seeing PJM West prices as relatively intact, but NI Hub as particularly negative. *Guidance revisions should be largely negative.*

Figure 35: 2016 Forward Prices Moves -> QoQ Updates on the Outlook

Mark-to-Market Changes - 2016 Forwards			
ATC Power Prices	30-Jun	30-Sep	% Change
ERCOT-Houston	41.63	40.05	-3.8%
PJM West	41.64	40.97	-1.6%
NI Hub	35.27	33.61	-4.7%
NYISO Zone A	39.77	39.23	-1.4%
Mass Hub	62.35	66.24	6.2%
Gas Prices	30-Jun	30-Sep	% Change
Henry Hub	4.24	4.08	-3.8%
DomSouth	3.26	2.95	-9.5%
WAHA	4.16	4.06	-2.4%
TETCOM3	4.27	3.89	-8.9%
Malin	4.14	4.02	-2.9%
AECO	3.62	3.49	-3.6%
TrancoZn4	4.26	4.13	-3.1%
Dawn	4.32	4.1	-5.1%
SoCal	3.62	3.49	-3.6%
PGECityGate	4.74	4.58	-3.4%
TranscoZn6	4.84	4.68	-3.3%
SoCalGas	4.39	4.26	-3.0%

Source: Platts and UBS estimates

Diving into the realized spot prices nationally

Texas spot prices were little changed YoY in the absence of any real summer heat while the Northeast hubs all showed declines with Mass Hub dropping nearly 20%. California was up strongly as the impact of the droubt continues. The story is similar with gas prices where Transco, Dominion South, and TECOM all experienced ~30% declines YoY to the $2/mmbtu range. The already low Leidy hub declined another 6% asking the question how low can regional natural gas go?

Northeast Gas spot fell into the $2.30-$2.60/mmbtu range.

Figure 36: Spot Prices – Down in NE, Up in California

	3Q13	3Q14	% Change
Average Spot Power Prices			
ERCOT Houston	$34.7	$34.4	-1.0%
ERCOT North	$32.4	$33.7	4.0%
Illinois Hub	$37.6	$36.5	-2.9%
PJM West	$38.9	$35.0	-9.9%
CAISO All Zones	$31.7	$38.7	22.0%
CAISO North Bay	$30.4	$34.4	13.0%
Mass Hub	$54.2	$43.6	-19.7%
Average Spot Gas Prices			
Transco Zone 6	$3.78	$2.57	-32.0%
HenryHub	$3.48	$3.93	13.0%
Dom South	$3.27	$2.33	-28.9%
WAHA	$3.50	$3.87	10.6%
TETCOM3	$3.52	$2.38	-32.5%
Transco Zn4	$3.79	$2.57	-32.3%
SoCalGas	$3.61	$4.20	16.4%
Leidy	$2.30	$2.17	-5.6%

Source: Bloomberg and UBS estimates

Ameren Corp. (Neutral; $40 PT)

IRP and Clean Power Plan could allow AEE to accelerate spending but even pushed forward capex still likely outside of earnings horizon.

Strongly unfavorable weather looks to leave Ameren with at best a slight YoY EPS improvement.

We estimate 3Q14 EPS for Ameren of **$1.26**, effectively flat versus 3Q13 and in-line with consensus with unfavorable July weather erasing the organic growth. With second quarter earnings Ameren noted a 35% decline in CDDs in July which they estimated as reducing earnings by $0.05-$0.10. August appears to have been slightly warmer than normal but September was also milder than normal despite heat later in the month. Aside from expectations of weak weather comps, we do not anticipate any real surprises with the typical higher earnings from Illinois rates, ATX rate base growth, and the savings on the $425Mn parent debt that matured in May (discussed later).

Despite TTM EPS at the high-end of the range, we estimate that a weak 4Q14 will leave FY results a penny below the midpoint.

TTM EPS $2.45 is towards the high-end of the $2.30-$2.50 FY14 guidance range but fourth quarter results are expected to be modest lower YoY due primarily to the negative impact of the Callaway nuclear refueling outage (~$0.08 anticipated) and return to normal weather (-$0.04). The Callaway outage is expected to last six weeks beginning this month according to SNL. Higher earnings from ATX, Illinois rates, and lower parent drag will be offsetting positives but the bias appears to be negative YoY. With our initial expectation of a $0.05 EPS decline in 4Q14 YoY, we estimate FY14 EPS of **$2.39** (in-line with consensus) and do not expect a guidance change.

Figure 37: 3Q14 Earnings Walk

3Q14 YoY Earnings Walk		
3Q13A	**1.25**	Notes
Weather vs. Normal in 3Q13	0.03	*Return to Normal Weather*
Weather vs. Normal in 3Q14	**(0.09)**	*Mixed weather with cold July and warm August*
Absence of Callaway Refueling Outage	0.01	*Removing Impact of Callaway Nuclear Refueling Outage*
Increase in IL Rates	0.01	*Net of Normalization*
IL Electric: Formulaic Rates ROE	0.01	*30-year Embedded is 3.6% vs ~3.3% avg. in 2Q14*
Gas Rate Case	0.02	*New Gas rates effective Jan 1st, 2014*
ATX	0.02	*Avg Ratebase increase YoY for FERC Trans. is $300M Higher in '14*
O&M, etc.	0.00	*Cost Inflation*
D&A	(0.01)	*Cost Inflation*
Reduction in Parent/Merchant Drag	0.02	*Most of 2014 Benefit is from Refi on Parent Notes in May*
Decline in Usage	(0.01)	*Decline in Electric sales volume*
Higher Effective Taxes	(0.00)	*Difference of ~37.8% ETR '13 vs 38.5% '14 Guidance*
3Q14E Adjusted EPS	***1.26***	
Consensus	*1.27*	

Source: Company Filings, FactSet, UBS Estimates

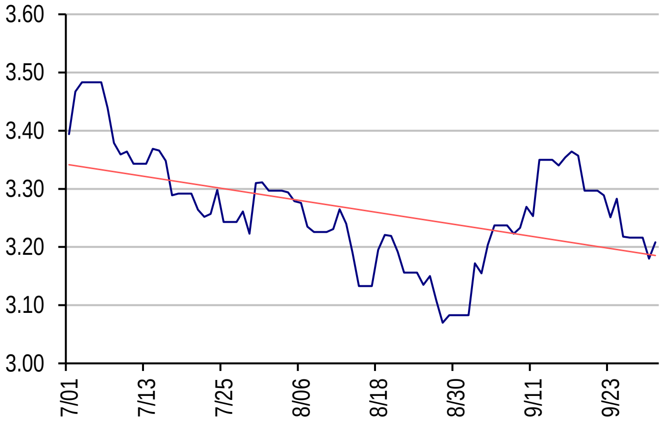
Links to our relevant recent research are below:

8/19/14 Breaking Down the New FERC ROE Methodology
8/7/14 Working Through the Regulatory Outlook

Figure 38: 3Q14 30-Year Treasury Movements

Source: FactSet

Figure 39: 2009-Current 30-Year Treasury Movements



Source: FactSet

New Integrated Resource Plan Targets the Coal Fleet

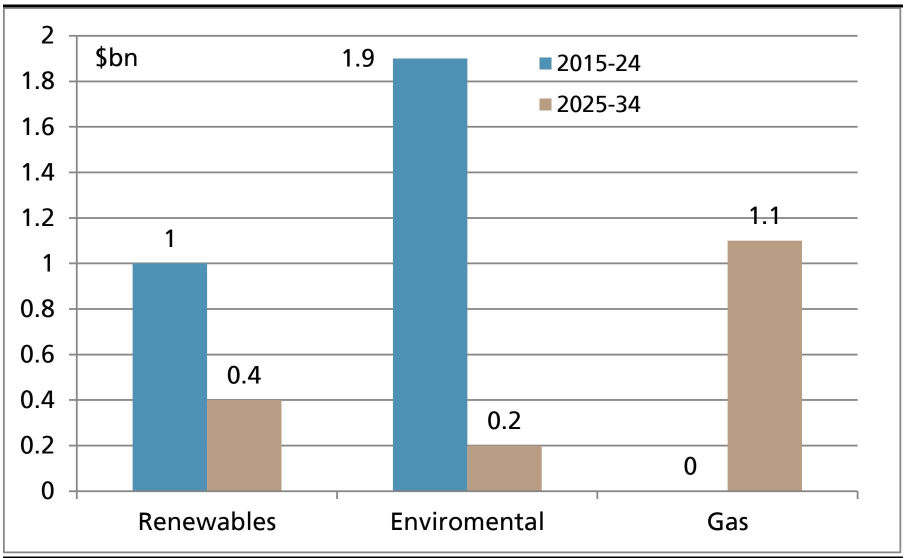
Ameren's latest Integrated Resource Plan (IRP) filed with the Missouri Public Service Commission plans for retiring 1,800MW of coal capacity (Sioux / Meramac), adding 600MW of gas (post 2025) and 478MW of renewables (ratable) over the 20 year period starting 2015, subject to the exact EPA rules that get implemented. As it stands now, the preferred plan under the IRP achieves reduction of CO_2 levels by 30% compared to 2005 by *2035*, as opposed to EPA proposals to achieve that target by 2030. Management has stated most of the nearer term capex is already included in current filings – and any increase in capex that may be there is not expected to be substantial enough to move the needle for the existing 2% CAGR target. We see this as an evolving plan, the details of which will materialize based on the exact environmental rules that get mandated over time. The chart below shows investments needed to be made in generation assets under the preferred plan. Below we discuss the preferred plan as well as some of the alternative scenarios considered.

Ameren MO IRP:
-1,800MW of Coal
+600MW of Gas
+478MW of Renewables

Over 50% of Ameren 2013 capacity was coal-fired.

Despite increased spending, mgmt. does not see an increase in the 2% 2013-2018 ratebase CAGR with the focus outside of that horizon.

Figure 40: Generation investments under AEE's preferred plan ($bn)



Source: Company Filings

Retire ~1,800MW of coal (a third of their coal portfolio)

Ameren anticipates sharp reduce of its coal fleet as it approaches its 70th birthday

Management reiterated their overall preference to keep the coal units running till the end of their economic life. We show in the table below current age and expected date of retirement for AEE's coal fleet.

Figure 41: AEE's Missouri Coal Fleet: estimated retirement year

Coal plant	Units	Capacity	Year in service	Current age	Estimated retirement	Age at retirement
Labadie	4	2,374	1970-73	41-44	2042	65-70
Rush Island	2	1,182	1976-77	37-38	2046	69-70
Sioux	2	972	1967-68	46-47	2033	65-66
Meramec	4	831	1953-61	53-61	2022	61-69
Total	12	5,359	1953-77	37-61		61-70

Source: Company Filings and UBS Estimates

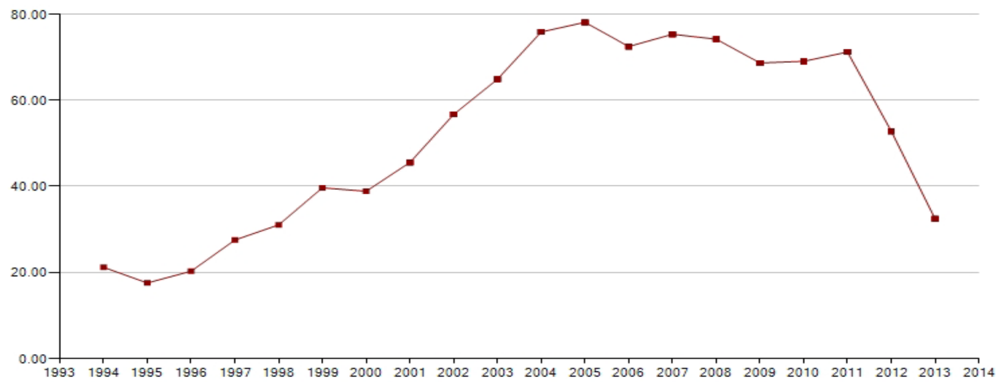
Sioux: Under the IRP Sioux will be retired by the end of 2033 – and this outcome holds for the preferred plan as well as under all other possible scenarios that AEE considers. So this is more or less an announcement that Sioux will shut down by end 2033 and not retrofitted.

Ameren Missouri announces plans to close Meramec before it requires significant environmental capital spending.

Meramec: Ameren announced earlier this summer that it was closing the 873MW Meramec coal plant, one of the oldest in the United States, by 2022. In its IRP management disclosed that Units 1 & 2 will be converted to natural gas in early 2016 although all units will still be retired by 2022. The other retirement options that AEE considered for Meramec include retirement by December 31, 2015, and retirement by December 31, 2022, but this was not included in the preferred base plan.

Meramec went in service in the 1950s and Kevin DeGraw, VP of Power Operations for Union Electric (Ameren Missouri) told SNL that AEE believes it can operate the plant for at least the next few years without significant capex but "substantial pollution equipment" requiring hundreds of millions in capex would be unavoidable after 2022. After reaching a peak capacity factor of ~mid-70% from 2004-2008, capacity factors have been eroding before falling in 2012 (53%) and 2013 (32%) although YTD 2014 capacity factor is close to 70% this winter. Meramec was supplied by Peabody Energy's North Antelope Rochelle PRB mine, the largest in the United States.

Figure 42: Meramec Entire Plant Capacity Factor (%)



Source: SNL

Labadie and Rush Island: The retirement dates for Labadie and Rush Island, based on life expectancy estimates, are beyond the 20-year IRP horizon (see table above), so they continue to operate under AEE's preferred plan. However, alternative plans did consider retirement of Labadie by end 2023, and retirement of Rush Island by end 2024 - based on considerations to avoid retro fitting costs.

Add 600MW of combined cycle gas unless EPA hold firm

Although the preferred plan is to add 600MW combined cycle by 2034, it is based on the expectation that the final implemented EPA rules will be much less strict than those currently proposed (which is management's expectation). Management said that in case current proposal are accepted, they would need to accelerate gas build out to 1200MW combined cycle by 2020.

Management said that in case current proposal are accepted, they would need to accelerate gas build out to 1200MW combined cycle by 2020

Increasing renewables mix as well with 400MW wind and 45MW solar

AEE's preferred renewable build out plans to add 400 MW of wind, 45 MW of solar, 28 MW of hydro and 5 MW of landfill gas by 2034. Below we show the build out schedule under the preferred plan. Most of the wind build out is expected in the 2019-26 period (back-heavy); in terms of near term build, 15MW of solar are projected over 2015/16.

Figure 43: Renewable capacity additions under preferred plan (MWs)

MW	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Wind	-	-	-	-	50	50	-	100	-	100	-	100	-	-	-	-	-	-	-	-	**400**
Solar	5	10	-	-	-	-	10	-	-	-	10	-	10	-	-	-	-	-	-	-	**45**
LFG	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**5**
Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5	10	-	-	-	**20**
Total	5	10	0	0	55	50	10	100	0	100	10	100	10	0	5	5	10	0	0	0	**470**

Source: Company Filings

After Nine Months, Noranda's Options with PSC Look Exhausted

On October 1st Missouri Public Service Commission (PSC) unanimously voted against Noranda's argument that Ameren Missouri overearned as Noranda did not meet the burden of proof required. As a reminder, in late August the Missouri PSC officially ruled against aluminum company Noranda's request for a 25% rate decrease (i.e. the rate shift docket) as the Commission did not believe that Noranda had such poor liquidity that it was unviable without a rate decrease and that ratepayers would be in a better situation after the rate decrease.

While Noranda may request a rehearing in the overearning docket as it did with the rate-shifting docket, we do not see a risk here. Noranda does not appear to have given up the fight completely as there remains the possibility that the company opts to resurrect the issue with the Missouri General Assembly; however, there is no assurance that the outcome will be any different.

Noranda Rate Shift Complaint Docket: EC-2014-0224
Noranda Earnings Complaint Docket: EC-2014-0223

MO electric ratecase filed, primarily for Callaway's reactor vessel head

Missouri PSC will be busy with Ameren and Empire District Electric rate cases in the upcoming months.

On July 3, the company filed for a 9.7%, $264M rate increase in MO (10.4% ROE on 51.6% equity for $7.3B ratebase at yearend 2014), primarily to recover investments in nuclear safety, environmental controls, new substations and renewable generation through the end of this year. Half the increase is for recovery of net energy costs that would otherwise be fuel adjustment clause items and there is a $67M reduction in operating expenses incorporated as well. Given a true-up for six months of known and measurable changes, the filing was timed to incorporate 2014 capital and ratebase levels when the decision is expected in May 2015 and rates become effective in June 2015 (11 month maximum timeline; Docket: ER-2014-0258). PSC staff and intervenors testimony is due by December 5th and hearing are scheduled to begin February 23rd, 2015 – we do not anticipate any real updates here ahead of December filings.

Expect first datapoints in December when PSC Staff filings are made (December 5th deadline).

Investment recovery in the case includes:

- Replacement reactor vessel head for Callaway Energy Center
- Upgrades to coal-fired Labadie Energy Center's electrostatic precipitators for compliance with MATS
- a new substation in downtown St. Louis
- O'Fallon Renewable Energy Center (solar)

In the Illinois Electric Delivery Formula Rate Case Ameren filed on August 1st for $205Mn net revenue increase which was premised approximately evenly on recoverable costs/PP&E spending, 2013 revenue requirement reconciliation, and a similar adjustment for 2012. In late August the Illinois Commerce Commission (ICC) Staff proposed in-line revenue requirement with consumer advocates recommending a $199Mn increase. The ALJ's Proposed Order is expected November 7th with ICC decision the following month and new rates for January 2015. (Docket No. 14-0317)

Rolling up the parent drag: Ameren rolls $425Mn maturity into CP

Mgmt opts to not refinance the parent notes but let them mature and utilize commercial paper for now

Reducing its legacy parent drag related to the IPH fleet has been a stated priority for Ameren this year and a large piece of that relates to the parent debt. The 8.875% parent notes matured in May and management opted to roll the debt into commercial paper for the time and pay the balance down as it reaps the tax benefits from the IPH sale. Previous management guidance was vague here with a goal of "something less than that $425Mn." The company does not appear to have any real urgency to secure permanent financing and we continue to assume that this will be carried with minimal interest expense.

$200-300Mn of parent debt is expected to remain for Ameren but this relates to initial financing for ATXI as the parent is currently financing the initial construction of Illinois Rivers with a hypothetical capital structure in the early stages. Ultimately we would expect for AEE to finance its transmission projects at the operating company level, consistent with peers. At some point management anticipates

breaking this transmission out separately for financial reporting purposes but there is no real timeline.

Transmission ROEs may be cut, but robust pipeline is key to growth

Despite the probable reduction in FERC transmission ROEs from the pending MISO complaint case following the New England ruling in June, we continue to see transmission growth as the key to AEE's overall earnings growth quality, with several projects currently in the pipeline. There is $1.4B of multi-value projects at Ameren Transmission Company of Illinois (ATXI), including the $1.1B Illinois Rivers project, which has begun construction while the company awaits the final cost update now that the ICC has approved the route with an update available likely with 4Q14 earnings around February. The Spoon River project is estimated to cost $130M-$150M depending on route approvals as well. AEE requested an ICC Certificate of Public Convenience and Necessity in August, with a decision expected in mid-2015. Another $850M of local reliability projects at Ameren Illinois are planned as well from 2014-2018.

From 2013-2018, AEE projects a $3.4B increase in regulated infrastructure ratebase from $10.8B to $14.2B at a 6% CAGR, with more than half of the increase ($1.825B) coming from transmission investment. This would ramp transmission ratebase up from 6.9% to 18.1% in the 5-year period, supporting the company's expectation for 7%-10% EPS CAGR as well.

ATXI requested FERC affirm its eligibility for the 50 bps, with the expectation that FERC would provide that affirmation if and when it responds to the complaint.

With respect to the Section 206 ROE complaint in MISO, there is no timeline for a FERC decision. ATXI currently earns 12.38% (and no actual has been booked for an expected reduction in earnings), which does not include a potential 50bps independence adder that ATXI believes it is entitled to. In the company's answer to the complaint in November 2013, ATXI requested FERC affirm its eligibility for the 50bps, with the expectation that FERC would provide that affirmation if and when it responds to the complaint itself. At a conference in September management stated that based upon its projected 2018 transmission ratebase, a 100bp change translates into ~$0.06 delta for EPS.

Competitive transmission opportunities under FERC Order 1000 will eventually become another source of growth for AEE, with the company seeing potential in MISO and beyond in PJM and SPP as well. The MISO planning process is starting now and expected to last ~15 months, with an expectation that projects will be identified for consideration by the end of 2015.

Valuation: Maintain $40 PT

We continue to use an in-line multiple at Missouri despite the most recent setbacks as it appears that Ameren and other utilities are continuing to take the right steps to push favorable regulation across the finish-line sooner rather than later. We value transmission at a 1.5x premium to the distribution and generation segments.

Figure 44: Ameren Sum-of-the-Parts

Ameren Sum of the Parts Valuation										
All figures in US $ million except per share data	2016 Net Income	EPS	P/E Multiple					Equity Value		
			Low	Peer Multiple	Prem /Disc	Base	High	Low	Base	High
Ameren Missouri	$403	1.65	13.5x	14.5x	0.0x	14.5x	15.5x	$5,444	$5,847	$6,250
Ameren Illinois	$210	0.86	14.0x	14.5x	0.5x	15.0x	16.0x	$2,941	$3,151	$3,362
Ameren Transmission (ATX)	$61	0.25	15.0x	16.0x	0.0x	16.0x	17.0x	$910	$970	$1,031
Parent Unallocated Items	($15)	(0.06)	13.5x	14.5x	0.0x	14.5x	15.5x	-$204	-$219	-$234
Total / Implied Utilities	$659	2.70	13.8x			14.8x	15.8x	$9,091	$9,750	$10,409
NPV of Acquisition Tax Benefits								$180	$180	180
Pension and OPEB Liabilities								($75)	($75)	(75)
Cash Contribution								($60)	($60)	(60)
Non Utility Value, Net of Debt								$45	$45	45
2016E Number of Shares Outstanding (Mn)								244	244	244
Equity Value per Share (Netting Parent Debt)								$37.39	$40.08	$42.78

Source: Company Filings, FactSet, and UBS Estimates

American Electric Power (Neutral; $55 PT)

Nickel miss on mild weather but expect 2015/16 guidance raise on higher power pricing

ESP/PPA outcomes are unlikely before the Ohio election.

We expect AEP to report **$1.00** vs consensus $1.05, with the miss generated primarily by very mild weather this quarter (despite last year's 3Q13 also being mild by a penny) and the planned acceleration of $60M of future O&M (2015/16) into 2H14. We think generation and marketing should be a big drag on 3Q too, with management initially guiding to -$0.20 for the year, although strong winter weather and pricing has produced +$0.54 through June 30. We assume that the initial guidance still applies to 3Q, with the mild weather exacerbating the effect for a net result of -$0.08. Transmission JVs provide an incremental +$0.03 and rate increases add another +$0.05. River operations improvement adds another penny.

Figure 45: AEP 3Q Walk

3Q14E AEP Earnings Walk	EPS
3Q13A Adjusted EPS	**1.10**
Weather Last Year vs. Normal	0.01
Weather this year - very mild entire quarter	(0.07)
O&M Flat across Corp in 2014	(0.04)
Transmission	0.03
Gen and Marketing	(0.08)
Off-system sales	(0.01)
Load Growth - Flattish	-
Rate Changes	
FERC Formula Rates	0.01
Kentucky asset transfers (Mitchell)	0.01
Ohio (Dist Investment Rider)	0.01
APCo Asset Transfers (Amos)	0.02
Total Rate Increases	**0.05**
River Ops Return Improvement YoY	0.01
Retail Margins	-
Tax Rate (Tax Adjustment, benefit was last yr)	-
3Q14e Ongoing Earnings UBSe	**1.00**
Consensus	***$1.05***
2014 Guidance	***$3.35-$3.55***

Source: UBS estimates, Company filings, FactSet

Stronger power pricing curves since Nov 2013 guidance warrant a raise

In April, 2014 guidance was raised $0.15 and we don't expect any change to the range of $3.35-$3.55 (vs UBSe $3.48 and consensus $3.48), with TTM $3.55 based on our $1.00 3Q estimate and 4Q expected to be about -$0.04 lower on the acceleration of O&M alone. However, we do expect the company to refresh and raise by $0.15-$0.20 its 2015-2016 guidance about that was initiated at EEI last year and currently sits at 2015 $3.30-$3.60 (UBSe $3.66 vs consensus $3.56) and 2016 $3.45-$3.85 (UBSe $3.80 vs consensus $3.73). Higher power pricing and spark spreads for the unhedged portion of the merchant fleet have had a strong positive effect this year, first through the polar vortex and more recently through a late-summer/fall strengthening of the forward curves. The 2016 guidance also needs to be raised for the impact of about $60M (+$0.08) planned O&M acceleration into this year.

Higher power prices and lower O&M warrant a $0.15-$0.20 guidance raise for 2015/16.

Figure 46: Impact of Commodity Changes on Nov 2013 EEI Guidance

AEP Genco Gross Margin Delta Oct 2014 vs Nov 2013 Guidance (UBSe)	2014	2015	2016
AD Hub Peak ($/MWh)	1.85	5.75	3.80
MichCon Gas ($/MWh @ 7.1 HR)	4.87	1.18	(0.21)
Spark Spread ($/MWh)	(3.02)	4.57	4.01
TWhs Peak	8	8	8
AD Hub ATC ($/MWh)	1.48	3.47	2.76
TWhs ATC	30	30	30
Open Gross Margin Delta (UBSe; $M)	20	140	114
Gross Margins Hedged in Nov 2013	80%	0%	0%
Hedged Gross Margin Delta (UBSe; $M)	4	140	114
Additional 1Q hedging to lock in gains (UBSe) *	29	14	-
Hedged Gross Margin Delta (UBSe; $M)	33	153	114
UBSe EPS Commodity Impact on Oct 8, 2014	0.04	0.21	0.15

* Assume 50% of remaining open 2014 output and 20% of open 2015 output is sold at peak pricing

Source: Company filings, UBS Estimates, Bloomberg

Figure 47: Adjusted Management Guidance vs UBSe, 2014E-2016E

Adjusted Guidance vs UBS Estimates	2014	2015	2016
EEI Nov 2013 Guidance	3.20-3.40	3.30-3.60	3.45-3.85
Midpoint	*3.30*	*3.45*	*3.65*
EPS Impact of Commodities on Genco (UBSe)	0.04	0.21	0.15
Weather, Off-system sales, Other	0.07	-	-
O&M accel $60M from 2016 into 2H14	(0.07)	(0.01)	0.08
Assume +1.0% load growth in 2014 vs +0.1% guidance	0.08		
EPS impact of $300M higher transmission investment	0.01	0.03	0.03
UBSe Adjusted EEI Guidance Midpoint	3.43	3.68	3.91
UBSe Estimates	3.48	3.66	3.80
UBSe Previous Estimates	3.54	3.66	3.79
Consensus	3.48	3.56	3.73
AEP Official Guidance	3.35-3.55	unch'd from EEI	

Source: Company filings, UBS estimates, FactSet

Our estimates are either above or at the higher end of management guidance, although look more in-line when adjusted for commodities, as shown the table above. Our regulated utility estimates reflect a peak in 2016 from rate increases in Kentucky and APCo as well as O&M savings resulting from this year's acceleration followed by a backwardation in 2017-2018. Our utility assumptions further reflect

our belief that APCo is likely to remain challenged over the next few years to earn its authorized ROE in West Virginia (~9% of total ratebase). In the table below we've adjusted management's guidance for various factors including the acceleration of 2016 O&M into 2H14, stronger load growth than anticipated this year (we assume 1% vs 0.1% in the guidance, with every 0.5% = $0.04 EPS), additional transmission investment, and the impact of commodities at Genco which remain elevated (although off their May peak). Note that our 2016 estimate includes $0.08 of 1x O&M savings to account for the cost shift from 2H14, which we exclude from our valuation below. With our 2017-2018 estimates reflecting a more normalized O&M (-$0.08 from 2016) as well as a topping out of earned ROEs (except for West Virginia), our estimates for the regulated utilities become somewhat backwardated in 2016+, although this is offset in the consolidated numbers by a growing independent transmission ratebase.

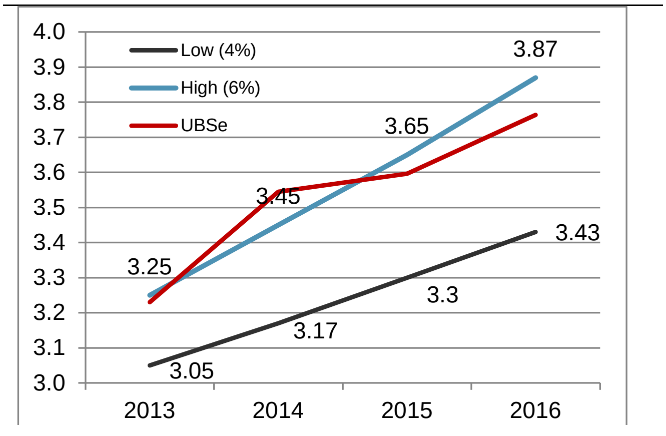
Figure 48: EPS by Segment, 2013-2018E – Utility-Level Expectations Included

EPS	2012	2013	2014E	2015E	2016E	2017E	2018E
Appalachian Power	0.53	0.48	0.54	0.66	0.71	0.64	0.66
Wheeling Power	0.08	0.08	0.09	0.09	0.09	0.10	0.10
Indiana Michigan Power	0.24	0.36	0.42	0.43	0.48	0.45	0.46
PSC of OK	0.24	0.20	0.19	0.21	0.23	0.23	0.22
SWEPCo	0.43	0.31	0.39	0.42	0.46	0.44	0.45
Kentucky Power	0.11	0.03	0.16	0.18	0.19	0.18	0.18
Kingsport Power	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Generating Company	0.05	0.05	0.06	0.06	0.07	0.07	0.07
Ohio Power	1.09	1.05	0.47	0.49	0.57	0.54	0.54
Texas Central	0.23	0.13	0.14	0.16	0.18	0.19	0.20
Texas North	0.06	0.08	0.08	0.08	0.08	0.09	0.09
Total Utilities	$ 3.06	$ 2.76	$ 2.54	$ 2.78	$ 3.06	$ 2.94	$ 2.98
Transmission Holdco		0.16	0.30	0.40	0.52	0.66	0.79
Transmission Guidance			*0.30*	*0.38 - 0.39*	*0.45 - 0.51*	*0.57 - 0.67*	*0.67 - 0.80*
AEP River		0.02	0.02	0.02	0.02	0.02	0.02
Genco	0.62	0.24	0.63	0.45	0.20	0.25	0.35
Corp & Other & eliminations		0.03	(0.01)	(0.00)	(0.01)	0.01	0.00
Consolidated	$ 3.09	$ 3.23	$ 3.48	$ 3.66	$ 3.80	$ 3.88	$ 4.14
Prior estimates			*3.54*	*3.66*	*3.79*	*3.88*	*4.15*
Consensus			*3.48*	*3.56*	*3.73*	*4.01*	
EPS CAGR 2013-2016E					*5.6%*		
Guidance			*3.35-3.55*	*3.30-3.60*	*3.45-3.85*		

Source: Company filings, UBS estimates, FactSet

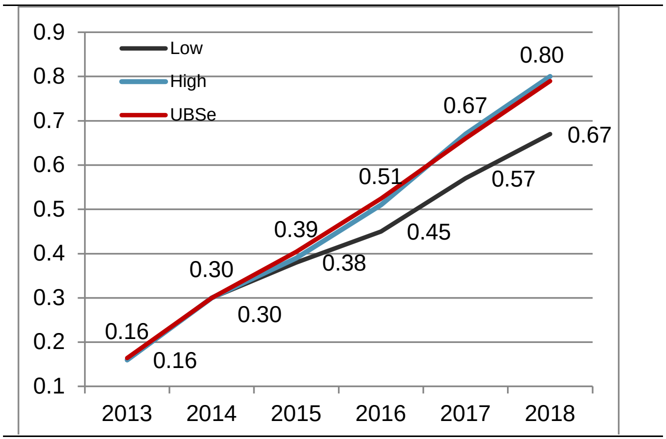
Again we highlight the potential for substantial earnings uplift by employing double leverage at AEP TransCo; doing so would likely keep the earnings at the top-end of the trajectory. *See below for additional detail.* We have also incorporated the incremental $300M of transmission spend announced this year (~75% TransCos and 25% Opcos), which should translate into an incremental $0.03 of overall earnings in 2015 ($0.02 at the TransCos).

Figure 49: AEP EPS Growth Guidance (2013-2016)



Source: Company Filings and UBS Estimates

Figure 50: AEP TransCo EPS Guidance



Source: Company Filings

Long-term growth rate most likely to be updated at EEI

If any update is required, we would expect that ton occur at EEI this year. We continue to believe that AEP will have no trouble in 2014 meeting or even exceeding its 4-6% growth target off a base of original 2013 guidance $3.05-$3.25. With full-year 2013 operating EPS of $3.23 management has set a readily achievable earnings target as it is starting its trajectory nearly $0.10 above this EPS midpoint. The midpoint of 2014 guidance ($3.45) is equal to the high-end implied by its 4-6% long-term growth rate indicating that even with no additional earnings in 2015 or 2016 it will be within its target range. We also believe, however, that maintaining this growth trajectory in 2017+ will likely require the company to improve its West Virginia ROEs substantially (as noted previously).

Upside possible from growth in shale producing territory

Excluding shuttered Ormet, 2Q industrial load improved a healthy 4.5% YoY while the more volatile residential and commercial sectors declined -1.5% and improved +0.4%, respectively. YTD total normalized load has improved +2.3% YoY (excluding Ormet), with regional results ranging from +0.6% at APCo to +4.6% at AEP Texas. Notably, the shale producing regions within AEP's service territory continue to grow at a remarkable clip, producing 2Q load growth of +39% vs non-shale declining -1.6%. Utica industrial load growth is up north of +50%. We continue to believe that AEP's sales volume assumptions embedded in guidance are very conservative, in the band of negative 0.5% to positive 0.5%, versus "the classic 1%-to-2% load growth" of prior years. Underpinning all of this improvement is continued above-average GDP growth in AEP’s territory and although employment growth is below-average, the Western territory has been increasing at ~1.5% which is much more in-line with that of the larger United States.

Figure 51: AEP Weather Normalized GWh Sales Growth YoY

	1Q13	2Q13	3Q13	4Q13	2013	1Q14	2Q14	YTD14
Residential	1.3%	-0.1%	-1.8%	0.9%	0.0%	4.4%	-1.5%	1.8%
Commercial	0.5%	-2.2%	1.2%	0.2%	-0.1%	2.9%	0.4%	1.6%
Industrial	-3.6%	-3.0%	-1.2%	1.6%	-1.6%	2.2%	4.5%	3.4%
Total	-1.5%	-2.7%	-1.5%	-0.8%	-1.6%	1.5%	-0.5%	0.6%
Total Ex-Ormet	-0.6%	-1.9%	-0.7%	0.9%	-0.6%	3.2%	1.3%	2.3%

Source: Company Filings, UBS Estimates

AEP follows FE's lead on compensation for its Ohio coal fleet

AEP requested an initial $2/MWh PPA rider for 2.7GW of its Ohio merchant coal (4 of 5 stations) for the life of the assets. AEP stated that a motivation for the request is that it "eliminates investor reluctance to the State of Ohio". This update to AEP's pending ESP follows a FE's comparable petition in August for ~3.2GW of generation – a docket that is seeing an increasing number of interveners. While Staff notably rejected the notion of even including a rider for AEP's stake in OVEC under its testimony in the existing ESP docket, we wouldn't be surprised to see the subject revisited by the Commission (even outside of the current case). AEP has asked for the contract to take effect in June 2015.

Figure 52: AEP's merchant coal portfolio

PJM Fleet Stats	Capacity (MWs)	Cap Factor	Output (TWhs)		Seeking Contract?
Coal Units					
Cardinal	595	55%	3		Yes
Stuart	603	55%	3		Yes
Gavin	2,640	55%	13		
Zimmer	330	55%	2		Yes
Mitchell (Retiring in 2015)	780	55%	4		
Conesville	1,139	55%	5		Yes
Total AEP Merchant Coal in Ohio	6,087			Total MWs:	2,667

Source: Company reports and UBS estimates

No requirement to clear RPM, avoiding jurisdiction issues

Will NOT follow the NJ and MD example – most likely

The request notably does not require the plants to clear the RPM capacity auction in order to be paid. This should help avoid the problems encountered in Maryland last year when the state sought to encourage new generation construction with state PPAs that were conditional on clearing capacity markets (with the intention of providing customers a net benefit). Recall that the Maryland PPAs were rejected by the courts as state interference in PJM's interstate commerce and the FERC's authority to regulate capacity pricing under the Federal Power Act.

Will others follow suit? We have to imagine AES will at a minimum

The plants included in AEP's petition include units that are co-owned with DPL (AES is parent) and DUK (soon to be DYN), suggesting that if successful, the other owners are likely to seek similar treatment. Specifically, we see AES (through DPL) as highly likely to ask as part of its next ESP filing (current term expires in Dec '16), suggesting its next filing is a 2015 event. As for Dynegy, we note continued commentary suggesting it would not pursue state backed PPAs, seeing the analogy as too close to MD and NJ (CEO Flexon explicitly stated this intention on transaction call in August). However, if ultimately successful for Ohio peers, we have to imagine even DYN would consider it.

Figure 53: Attributable MW ownership to Parent Companies

Ownership (%)	AEP	DUK/DYN	DPL(AES)
Cardinal	100.0%		
Conesville	71.2%	20.4%	8.4%
Stuart	26.0%	39.0%	35.0%
Zimmer	25.4%	46.5%	28.1%

MW Ownership	AEP	DUK/DYN	DPL(AES)
Cardinal	592		
Conesville	1,149	312	129
Stuart	600	900	808
Zimmer	330	605	365

Source: SNL, Company filings

Below we include the forecasted impacts from the Ohio PPA rider. The numbers are combined for Cardinal, Conesville, Stuart and Zimmer. We also include the

plant economics for each for AES' proportional ownership in those plants in the following table.

Figure 54: Forecasted Ohio PPA Rider Impacts (Combined Cardinal, Conesville, Stuart and Zimmer)

Weather Normalized Case, $ in Millions (Nominal)											
Year	2015 (Jun-Dec)	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total
PJM Revenues	$434	$861	$901	$979	$1,052	$1,034	$1,107	$1,234	$1,232	$1,284	$10,118
Agreement Costs	$492	$930	$947	$997	$1,062	$1,033	$1,061	$1,260	$1,245	$1,301	$10,328
Net PPA Rider Credit / (Charge)	($58)	($69)	($46)	($18)	($10)	$1	$46	($26)	($13)	($17)	($210)
AEP implied EPS estimate	($0.08)	($0.09)	($0.06)	($0.02)	($0.01)	$0.00	$0.06	($0.03)	($0.02)	($0.02)	

Source: Company filings

Contract Proposal Appears Materially Above Market

Below we present our estimations of the plans for each of the four plants as well as our underlying assumptions. While AEP states that the average customer would see a $2/MWh uplift initially, we estimate the uplift to the plants is closer to ~$19/MWh based on our latest assumptions of forward curves. A big swing factor remains the capacity factor projected on the units, which appears to be a key variance in our assumptions (as was seemingly the case in our prior FE calculations). We estimate FE's request is closer to ~$21/MWh above market.

We think AEP may have greater leverage to contracting approvals than FE given its un-levered Genco

Max upside case is ~$0.28

- We estimate the benefit to AEP at **$0.12 EPS for just Conesville** assuming economics below, with more meaningful upside if additional plants are approved. Our baseline remains just one plant from FE & AEP each is retained.
- The table below *excludes* the proposed rider for the additional 435 MW of capacity through AEP's interest in the OVEC plant, included in the original ESP.

Figure 55: AEP Projections – Fundamental assumptions suggest significantly above market as well

Regulatory assumptions	
ROE	11.23%
Effective tax rate	37%
Assumed debt (%)	50%
Assumed equity (%)	50%
Cost of debt	4.73%

UBS view vs filed assumptions for 2017	
2017 Power Revenues	605.3
2017 Capacity Revenues	85.9
Total UBS projected PJM revenues	705.1
AEP Projections of PJM Revenue (Using Avg of High/Low Forecast)	920.0
Difference in PJM Revenue Assumptions ($mn)	214.9
Total Estimated Generation	14.7
Above market price, UBSe vs. AEP Calcs on PJM Rev's ($/MWh)	**14.7**
AEP Projections of Agreement Costs	912.0
Difference in UBSe PJM Revenue vs. Agreement Costs	206.9
Above market price, UBSe vs. Agreement Costs ($/MWh)	**14.1**

Cardinal		**2017**
AEP's Owned Capacity (MW)		592
Capacity factor, UBSe		70%
Generation (TWh)		3.6
Fuel Cost ($/MWh)		25.0
O&M ($/kW-yr), UBSe		50.0
O&M ($ Mn)		29.6
Power Prices ($/MWh), AD Hub - Avg Peak/ATC		41
Capacity Prices	59	120.0
Annualized Capacity ($/MW-day)		94.7
EFOR (%)		7%
Capacity Payments ($ Mn)		19.0
EBITDA		**48.6**
Maintenance Capex ($/kW)		5.0
Maintenance Capex ($ Mn)		3.0
FCF		**45.7**

Conesville		**2017**
AEP's Owned Capacity (MW)		1,149
Capacity factor, UBSe		50%
Generation (TWh)		5.0
Fuel Cost ($/MWh)		29.9
O&M ($/kW-yr)		50.0
O&M ($ Mn)		57.5
Power Prices ($/MWh), AD Hub - On Peak		45
Capacity Prices	59	120.0
Annualized Capacity ($/MW-day)		94.7
EFOR (%)		7%
Capacity Payments ($ Mn)		37.0
EBITDA		**54.2**
Maintenance Capex ($/kW)		5.0
Maintenance Capex ($ Mn)		5.7
FCF		**48.5**

Stuart		**2017**
AEP's Owned Capacity (MW)		600
Capacity factor, UBSe		70%
Generation (TWh)		3.7
Fuel Cost ($/MWh)		26.7
O&M ($/kW-yr)		50.0
O&M ($ Mn)		30.0
Power Prices ($/MWh), AD Hub		41
Capacity Prices	59	120.0
Annualized Capacity ($/MW-day)		94.7
EFOR (%)		7%
Capacity Payments ($ Mn)		19.3
EBITDA		**42.9**
Maintenance Capex ($/kW)		5.0
Maintenance Capex ($ Mn)		3.0
FCF		**39.9**

Zimmer		**2017**
AEP's Owned Capacity (MW)		330
Capacity factor, UBSe		80%
Generation (TWh)		2.3
Fuel Cost ($/MWh)		25.8
O&M ($/kW-yr)		50
O&M ($ Mn)		16.5
Power Prices ($/MWh), AD Hub		40
Capacity Prices	59	120.0
Annualized Capacity ($/MW-day)		94.7
EFOR (%)		7%
Capacity Payments ($ Mn)		10.6
EBITDA		**26.27**
Maintenance Capex ($/kW)		5
Maintenance Capex ($ Mn)		1.65
FCF		**24.6**

Source: AEP Filing before the PUCO, Company reports, SNL, and UBS estimates

Understanding the discrepancy in EPS uplift

We emphasize that the discrepancy between our EPS estimate and management's implied EPS estimate from its filing relates to the assumed revenues to the plants. We estimate our revenues using 2017 annualized capacity payments and peak-weighted AD Hub prices. We think the discrepancy is likely due to differences in capacity factors, ancillary revenues, and out-of-market assumptions for the forward curve.

But where's the pushback? We believe price at a minimum.

The question remains *why* Ohio would need to contract for these plants now – and under whose interest. Given the focus on not just jobs, but also long-term rate stability and perceived value, we view the exact pricing of any deal will be critical to any eventual settlement. Notably different from previous interventions, there is not the explicit threat (yet) of plant retirements without payments.

What's next? Looking towards FirstEnergy's process

We flag that FirstEnergy's testimony and hearings on the proposal are set for December 19th and January 20th, respectively. Settlement negotiations typically take place in this window, and we understand this is indeed the intention on the current filing as well. We caution that Staff is likely to be persistent in rejecting against the contract in its initial testimony.

But where will the power industry come out on this: Don't feed the bears?

We flag that EPSA (Power trade association), P3 (PJM-specific power trade association), and DYN appear opposed to the OH contracts despite the requests from AEP & FE. We see this as among the few issues in recent memory where the industry could be poised to see in-fighting on a question of higher compensation for existing generators. We flag efforts by EXC in Illinois to save its nuclear fleet remain particularly committed to a 'market' solution (renewable, carbon, etc.) rather than bilateral approach taken in OH.

To see some of our recent reports on Ohio, please click on the links below:

"Asking for help when times are tough in Ohio"

"AES: Retaining the commodity upside in Ohio"

Settlement reached for transfer of Mitchell to Wheeling

In WV, the company has reached a settlement for the transfer of 82.5% of the Mitchell coal plant into Wheeling Power's (APCo) ratebase; hearings are scheduled for Sept 21 and final approval is still expected by the end of the year. Our estimates assume the transfer is approved. The agreement calls for another evaluation of need in 2020 for the remaining 17.5%, although an earlier request is not prohibited. Separately, the next step in the WV base ratecase is intervenor and staff testimony due Dec 8, 2014 with a final order due April 26. 2015.

Other regulatory activity updates

We expect a final order approving the non-unanimous (AARP is the holdout) settlement for the PS Oklahoma base ratecase in mid-October (imminently). The company still expects to file a base ratecase in Kentucky no later than December.

In Virginia, APCo's biennial rate review was filed in March 2014 and hearings commenced on Sept 16. The company's position is that it earned a 10.8% ROE for the two-year period, within the allowed earnings band and requiring no rate changes. Staff asserts that APCo earned a 12.85% ROE which would require a $22.5M refund. Staff also recommends a prospective ROE reduction to 9.3% with a band of 8.8% to 9.8%. If any changes are made, new rates would be effective Feb 2015.

It's unlikely that any action on getting Turk into ratebase will take place in Arkansas until after the election there, with the company likely waiting until 2015 to file a ratecase for it. With the Sierra Club successful in getting Turk's CPCN overturned, SWEPCo currently sells its portion of Turk's output into the market. Separately, we note Entergy's recent push for legislation in Arkansas to reduce regulatory lag in the state that could also benefit AEP (to a smaller extent).

A segment-by-segment commentary in 2Q vs 1Q TTM ROEs follows:

- Ohio Power (14.0% vs 13.3% QoQ): Likely see attrition due to continued customer switching, albeit the rate is slowing (expectation is for 71% by year end). The return here includes one-time items including transmission true-up and other adjustments that management expects will drive the return back around the 12% range.

- APCo (8.5% vs 8.4% QoQ): The low ROE here is divided between Virginia and West Virginia, with Virginia in much better shape at a 10.8% ROE (within an allowed band of 10.4%-11.4%). The company filed a West Virginia base rate case on June 30 for a $181.5M increase and a $44.6M vegetation rider. The case is intended to capture the December approval of the John Amos plant Unit 3 (1,300MW) transfer and should be finished up by April 2015 (a procedural schedule is pending).

  - APCo also has its bi-annual Virginia review, which began in March. The Virginia filing indicates the company earned within its allowed band for the prior (2012-13) period. We see more upside at West Virginia given the transfer and lag there whereas the benefit appears limited with the mandated filing in Virginia; overall we continue to expect improvement with this subsidiary. The question remains over time how APCo will take shape from a corporate structure perspective.

  - The company recently announced a settlement for the transfer of 50% of Mitchell to Wheeling, with 82.5% of this half to be ratebased now followed by a reevaluation of need in 2020 for the remaining portion. A final order is still possible by the end of this year. West Virginia continues to review the proposed merger of Wheeling and APCo as well. In Virginia, we continue to have confidence that the Mitchell transfer will ultimately be approved despite concerns from the VA SCC initially over the lack of prospective fuel diversity. Rather, the question remains over time whether the VA SCC will become interested – and to what extent the off-system sales mechanism will need to be re-adjusted to reflect a bifurcated portfolio between W Va and VA.

- KPCo (7.4% vs 6.1% QoQ): Expect continued attrition through 2014 subject to O&M management and off-system sales which could both help the ROE. ROE appears low due to the transfer of 50% of the Mitchell coal plant into ratebase in advance of an expected rate case filing at the end of 2014 (with

rates effective July 2015) as part of the transfer settlement. We expect continued attrition through 2014 subject to O&M management and off-system sales which could both help the ROE. Separately, on Aug 1, the Kentucky Public Service Commission (KPSC) found that KPCo's proposal for a $50M conversion of its 278-MW coal-fired Big Sandy Unit 1 to burn natural gas is the most reasonable lowest-cost option and granted the utility a Certificate of Public Convenience and Necessity (CPCN) to do so. The order is based on KPCo's assertion that the conversion is needed to comply with MATS, with the larger 800-MW Big Sandy Unit 2 slated for retirement in Jun 2015 as part of a 2011 plan to retire ~6 GW of coal-fired generation and convert to gas another ~1 GW. In the order granting a CPCN, the KPSC considered the results of KP's March 2013 request for proposals (RFP) for 250 MW of PJM capacity, comparing the results to a self-build conversion option after judging that the plant is too small to warrant the cost of an environmental retrofit for coal. The RFP results which were also rejected as too expensive included bilateral PPAs and the alternative of market purchases of capacity and energy from PJM for 10 years followed by new-build CT or CCGT. The CPCN was granted under case # 2013-00430.

- I&M (10.8% vs 11.6% QoQ): After rate cases completed in 2013, ROEs remain higher than the 10.2% authorized level ("not too far out of line" says management). The company recently filed to add five solar facilities (16 MW). The focus in this jurisdiction is increasingly on spending around Cook Nuclear Life Cycle Management, an area that management said they were making considerable success on; we expect more details here in subsequent quarters.

- PSO (9.1% vs 9.8% QoQ): PSO filed a non-unanimous settlement (AARP objecting) in its ratecase that keeps base rates flat but adds a $7M AMI rider in 2014 that increases to $27M by 2016. The company had filed for a $45M with a historical test year for a 10.5% ROE and despite the flat rates, management expects ROEs to improve as the reduced ROE is due in part to a portion of AEP's overall $60M accelerated O&M plan this year (which will result in lower O&M in 2016).

- SWEPCo (8.0% vs 7.9% QoQ): Lag exists for the treatment of Turk given Arkansas' denial of recovery. Management intends to push forward on getting Turk into Arkansas ratebase after the election there, with the company likely waiting until 2015 to file a ratecase for it. With the Sierra Club successful in getting Turk's CPCN overturned, SWEPCo currently sells its portion of Turk's output into the market. Separately, we note Entergy's recent push for legislation in Arkansas to reduce regulatory lag in the state that could also benefit AEP (to a smaller extent). Other potentially ROE-improving initiatives include a coming Texas transmission filing, O&M cuts, and generation/distribution investment growth including environmental capex.

- AEP Texas (13.1% vs 13.7% QoQ): Management reiterated that the ROE here is high but includes amortization of ~$100Mn of securitized stranded costs.

- AEP Trans Holdco (11.4% vs 9.7% QoQ): The improvement here is partially a result of a true-up of the previous year's underearning on higher investment. We took a deep dive into AEP's transmission spending following 4Q13 earnings *'Capitalizing on the Transmission Opportunity'* and note that the significant spending here ($1Bn of incremental PP&E YoY) is causing this segment to meaningfully under-earn in jurisdictions without forward rates; while FERC rates typically enable formula rate tariff treatment, they are typically up to one-

year lagging in AEP's case. The Transmission Cost of Service (TCOS) filing is made in July with rates going into effect shortly thereafter. AEP recently lost its bid to develop a solution for Artificial Island in PJM (the first FERC Order 1000 competitive transmission RFP), although the project was never in AEP's capital forecast nor management guidance.

- *More Leverage coming at the HoldCo too?* We continue to anticipate management will pursue more leverage at the transmission HoldCo, implementing a capital structure consistent with ITC and others with similar setups (~70% debt capitalization vs. 50% authorized at its utilities). While the two issuances thus far have been private placements (at Electric Transmission Texas and AEP Transmission Company), we would expect an eventual shift towards issuance of public debt at this segment. If AEP chooses to employ double leverage in a way consistent with peers, there is substantial room for improvement in the earnings profile.

Ongoing cash flows could probably support $1B-$2B of additional leverage

In 2016 and beyond, we see ongoing cash flows as able to support an additional $1B-$2B of incremental debt and remain within required credit agency metrics. Management also believes that it has the latitude to lever up the Holdco ~$1B without undue stress, but the decision to do so depends in part on their assessment of utility growth needs as well. Clues to the company's plans could come at EEI in November. For further detail, please see our **9/12 report "Levering the Story"**.

If AEP chooses to employ double leverage up to 70% debt/cap in a way consistent with peers, there is room for as much as $0.15 EPS improvement without significant balance sheet stress.

Figure 56: 2014-2016 Financing & New Debt Needs ($M; UBSe)

2014-2016 Financing & New Debt Needs ($M; UBSe)	2014E	2015E	2016E
Cash from Operations	4,068	4,416	4,514
Impact of Bonus Depreciation	459	-	-
Federal Cash Taxes Refunded (Paid)	(396)	(698)	(830)
Cash from Securitization	244	150	
Capital Spending	(4,050)	(3,836)	(3,822)
Other Investing Activities	(267)	(273)	(179)
Common Dividends @ $2.00/sh 2014-2016	(979)	(983)	(988)
Excess (Required) Capital	(921)	(1,224)	(1,305)
Financing ($M)			
Excess (Required) Capital	(921)	(1,224)	(1,305)
Debt Maturities (Senior Notes, PCRBs)	(1,090)	(1,323)	(715)
Securitzation Amortization	(316)	(371)	(380)
Interim Credit Facility (matures 2015)	-	(1,000)	-
Equity Issuances (DRP/401K)	100	100	100
Debt Capital Market Needs (New)	(2,227)	(3,818)	(2,300)
AEP Guidance	*(1,947)*	*(3,727)*	*(2,193)*

Source: UBS estimates, Company filings

AEP credit metrics supported by ongoing and $850M of transient cash flows

Our calculations show FFO/Debt of 20.4% in 2014 declining to 14.9% in 2018E in-line with mgmt's target of 15%-20%. Even with an additional $1B of debt, these metrics only decline ~90 bps. Similarly, average CFO/Debt from 2014-2018 of 15.4% as measured by Moodys would only decline to 14.7% with an extra $1B

of debt vs Baa rating criteria of 13%-22%. S&P FFO/Debt would also remain at 18.6% under the more stressed scenario vs credit "downside" at 13%. With AEP planning to issue ~$3B of incremental debt and $300M of DRiP/401k equity from 2014-2016 to fund $11.7B of capex, the company's near-term credit metrics are also supported by bonus depreciation ($459M) and 2014/15 cash from securitization of deferred fuel balances ($394M) in Ohio (subject to regulatory approval).

Figure 57: UBS estimated Credit Metrics vs Management Guidance, 2012-2018E

Credit Metrics (UBS estimates)	2012	2013	2014	2015	2016	2017	2018
EBITDA	4,796	4,878	5,162	5,221	5,256	5,361	5,546
Interest Expense	882	895	867	896	925	951	978
Interest and Investment Income	8	58	8	8	8	8	9
Income Taxes	683	805	888	859	849	890	935
FFO as defined as CFO pre-w/c	3,856	4,624	4,115	3,724	3,691	3,779	3,951
Cash from Securitization		-	*244*	*150*	-	-	-
Capex	3,025	3,624	4,050	3,836	3,822	3,825	3,825
Dividends	916	954	977	1,030	1,087	1,146	1,209
Total Debt	18,952	19,990	21,127	22,623	24,307	26,083	27,748
Securtized Debt	*2,281*	*2,686*	*2,614*	*2,393*	*2,013*	*1,633*	*1,253*
Total Capital	34,189	36,076	38,860	41,968	45,283	48,682	52,048
Deferred Inc Taxes	9,252	10,300	10,300	10,300	10,300	10,300	10,300
Cash	279	797	799	752	753	871	985
FFO minus Capex	831	1,000	65	(112)	(131)	(46)	126
FFO minus Capex minus Dividend	(85)	46	(912)	(1,142)	(1,217)	(1,192)	(1,083)
Net Debt & Equity Issued	60	949	1,237	1,595	1,785	1,876	1,765
FFO / Debt (excluding securitization debt)	23.1%	26.7%	20.4%	17.7%	16.6%	15.5%	14.9%
Company Guidance - FFO/Total Debt TTM 2Q14			*20.3%*	*Target 15%-20%*			
FFO / Interest	4.4x	5.2x	4.7x	4.2x	4.0x	4.0x	4.0x
Company Guidance - FFO / Interest TTM 2Q14			*5.0x*	*Target >3.6x*			
Debt / Capital	55.4%	55.4%	54.4%	53.9%	53.7%	53.6%	53.3%
Company Guidance - Debt / Capital (end of qtr)	*55.2%*	*54.3%*	*54.2%*	*Mid-50's*			
Debt / EBITDA	4.0x	4.1x	4.1x	4.3x	4.6x	4.9x	5.0x
EBITDA / Interest Expense	5.4x	5.5x	6.0x	5.8x	5.7x	5.6x	5.7x

Source: UBS estimates, Company filings

Competitive Transco projects could be levered to improve earnings

We see this as adequate to apply extra leverage to the Independent Transmission Holdco in support of FERC 1000 projects that could benefit from higher levels allowed by FERC. If AEP chooses to employ double leverage up to 70% debt/cap in a way consistent with peers, there is room for as much as $0.15 EPS improvement without significant balance sheet stress. This assumes $4.3B of 2016 transmission ratebase is double-levered from 50% to 70% (but earning an 11.4% equity return on 50% hypothetical equity) by issuing $860M of debt with little stress to the balance sheet.

Figure 58: Earnings Impact From Increasing Leverage on Transmission

Earnings Impact from Increasing leverage on transmission	2016E
ROE Transco	11.40%
Transco ratebase 2016E	4,300
Shares	493
Incremental debt from 50% to 70%	860
Interest rate of new debt	3%
EPS benefit of leverage	0.15

Source: UBS estimates

Concerns that EPA proposed carbon rules are "too aggressive"

While emphasizing its commitment to work with EPA as AEP did during the Mercury Rule comment period a few years ago, management has warned that the EPA's recently proposed carbon rules would lead to a "convoluted mess" in its current form, with too many interlocking changes required in too short a timeframe. For example, the generation mix, system dispatch, and market conditions must all change within the context of a multiple independent state review process within a few short years, turning the plan's much discussed "building blocks" into "pipe dreams". In particular, EPA's assumption that new natural gas fired generation could run at 70% capacity factors without adequate pipeline or transmission infrastructure in place was cited as not credible. Also problematic is EPA's expected 6% coal unit efficiency gains vs a "viable 1%", especially when capacity factors remain low due to the uneconomic dispatch of wind or lower carbon-intensive gas units. Furthermore, AEP noted that EPA's projection for 1.5% annual energy efficiency gains goes well beyond EPRI's (Electric Power Research Institute) 0.5%-0.6% theoretical maximum.

As proposed, EPA's carbon rules will lead to a "convoluted mess" and incidentally, 80% of the units to be retired under mercury rules are still being called upon in an unstressed, mild-weather 2Q.

Management also noted that the EPA's previous rule making effort on mercury is still a work in progress, with the bulk of coal retirements set to take place next year despite 80% of the units to be retired under mercury rules still being called upon in an unstressed, mild-weather 2Q.

Valuation: Reducing PT $1 to $55 for multiple contraction; Potential Genco upside

Our valuation is based on 2016E P/E multiples and a sum-of-the-parts where we ascribe a peer group multiple at distribution less a 5% discount considering the jurisdictions.

We apply a 1x premium multiple to transmission spending, reflecting both our expectations for further EPS upside from this segment as well as its premium return profile. We believe that transmission earnings will come in at the high-end of guidance and see further upside given the potential for enhanced leverage at the Transco. We continue to reflect a discounted valuation versus peers on its utility businesses to account for the conglomerate discount, as well as more challenging regulatory jurisdictions alongside

Latest capex revisions, and potential Transco leverage add upside to segment estimates

Our valuation of Genco is based on an 8.0x EV/EBITDA multiple minus $826M of debt there. This is using our projected $382 Mn in 2016 EBITDA for the segment, the projected trough year in projected EBITDA, we see possible upside to this estimate on any potential sale next year (with resolution of any pending PPA structures, which also remain excluded). With a net book value of $3.5B on AEP's

Applying 8x EBITDA to trough year is conservative in our view

balance sheet, there is the potential for another $0.25/sh of tax benefits (PV) at our valuation as well.

Figure 59: Application of Duke merchant sale metrics to AEP Genco

EV/EBITDA - Duke Sale	2015	2016	2017	Average
AEP Genco EBITDA ($M)	$569	$380	$418	
EV/EBITDA - Duke sale (with Synergies)	6.7x	8.3x	8.1x	
Implied EV AEP Genco ($M)	$3,814	$3,157	$3,383	$3,451
EV/EBITDA - Duke sale (without Synergies)	7.1x	9.7x	7.1x	
Implied EV AEP Genco ($M)	$4,042	$3,689	$2,965	$3,565

Source: Company Filings and UBS Estimates

A Conesville PPA could be worth up to $1/share

We estimate the EBITDA uplift from any contract is at least ~$65 Mn, with ~$10-$20/MWh uplift based off FE's initial ESP proposal * 71% ownership * 6.3TWh in 2013 for Conesville. In our view this could yet up to another $1/share in our valuation depending on the term of any arrangement (with further upside potential from additional assets contracted). *See above for further details on AEP's most recent Ohio PPA request.*

Figure 60: Updated AEP Valuation – Breaking out the Segment Value

Price Target - P/E Calculation						
	2016 EPS		Group P/E	Prem/(Disc)		$/shr
Utilities	$	3.06	14.7x	(5.0%)	$	42.76
Transmission		0.52	15.7x	0.0%		8.10
Parent & Other		0.02	14.7x	(5.0%)		0.27
Subtract 1x O&M		(0.08)	14.7x	(5.0%)		(1.02)
Total Regulated	$	3.52	14.2x	(3.1%)	$	50.10
Genco EBITDA	$	380	8.0x	EV	$	3,042
Genco EPS	$	0.20		Debt	$	826
				Equity	$	2,216
				Equity/shr	$	4.50
Total (ex-1x O&M)	***$***	***3.72***	***14.7x***	***(.2%)***		***54.60***

Source: Company Filings and UBS Estimates

Avista (Neutral; $30 PT)

Nickel beat on ERM; 2015 initial guidance probably below consensus

We expect AVA to report **$0.24** vs $0.19 last year and consensus of $0.19, with the beat driven by +$0.05 from the Energy Recovery Mechanism (ERM) vs. a very weak 3Q13, which had been -$4.6M (pretax) as a result of the closure of Colstrip last year. This year, the ERM stands at $4.9M of earnings benefit as of June 30, with company guidance expecting to be in the 90%/10% sharing band by yearend, implying at least a $5.5M benefit. This further implies at least an incremental +$0.6M in 2H14E vs -$4.6M in 3Q13 and another -$4.2M in 4Q13. Hence we also expect another strong comparison in 4Q barring an unforeseen reversal from higher power prices as a result of low precipitation or some other cause. We think rate relief across Wash, Idaho and Oregon should also provide another +$0.06 benefit. The sale of Ecova removes last year's $0.05 of earnings, which is partially replaced with ~$0.02 of earnings from the acquisition of AERC. With rates running seasonally in Alaska at about 2/3 revenue collected in 1H, we expect only $0.03-$0.04 in 2H14 vs an annual run rate closer to $0.11. D&A should be up -$0.03 and interest should be slightly higher as a result of $90M of debt issued at 0.8% in Aug 2013.

We expect at least an incremental +$0.6M in 2H14E vs -$4.6M in 3Q13 and another -$4.2M in 4Q13. This should be a nickel improvement in both quarters.

Expect initial 2015 guidance ~$1.95 vs consensus $1.99 and UBSe $1.98.

Figure 61: AVA Earnings 3Q Earnings Walk

3Q14 Earnings Walk	EPS
3Q13 Adjusted EPS	**$0.19**
Weather	$0.01
Sales Benefit	$0.04
ERM benefit	$0.05
Rate Relief	$0.06
Ecova	($0.05)
AERC	$0.02
O&M	($0.04)
D&A	($0.03)
Interest	($0.00)
Dilution	($0.01)
Other	($0.01)
3Q14e Adjusted EPS	**$0.24**
Consensus	**$0.19**
2014 Guidance	**$1.77-$1.97**

Source: UBS estimates, Company filings, FactSet

Figure 62: Expected Rate Relief in 2014

Rate Relief ($M)		
$	14.00	WA - Electric (Jan 2014)
$	1.40	WA - Gas (Jan 2014)
$	3.80	OR - Gas (Feb 2014)
$	7.80	ID -Elec (Oct 13)
$	1.30	ID - Gas (Oct 13)
$	28.30	pre-tax YoY impact
$	18.40	after-tax
$	0.06	3Q14 vs 3Q13 EPS

Source: Company filings, UBS estimates

Company to initiate 2015 guidance, probably a bit below consensus

We expect the company to initiate 2015 guidance of 4%-5% above the $1.87 midpoint of 2014 guidance, or ~$1.95, with a $0.20 range from $1.85-$2.05. Maintain PT of $30 for a previously reflected lower 2016 estimate and a compressed multiple of 14.2x vs 14.8x previously. Maintain Neutral rating.

We are reducing our PT from $33 to $30 for lower ests and a lower average peer 2016 P/E multiple.

Maintain Neutral rating.

Figure 63: AVA Estimates, 2013A-2017E

AVA		2013A	2014E	2015E	2016E	2017E
Segment EPS						
Avista Utilities (& AERC)		$1.81	$1.97	$2.02	$2.10	$2.20
Ecova		$0.12				
Other		($0.08)	($0.04)	($0.03)	($0.03)	($0.03)
UBS Estimates		**$1.85**	**$1.93**	**$1.98**	**$2.07**	**$2.17**
Prior UBS estimate		$1.85	$1.93	$1.98	$2.07	$2.17
Consensus			*$1.91*	*$1.99*	*$2.05*	
Guidance	*"High-End" of*	*1.78-1.96*				
EPS Growth Implied off 2014 guidance $1.87 (LT guidance 4%-5%)				*6.1%*	*4.3%*	*4.7%*
ROE Earned at Utility (8.4%-9.1%, including 60-70 bps reg lag)				*9.3%*	*9.1%*	*9.1%*

Source: UBS estimates, Company filings, FactSet

As a reminder, the company recently updated its 2014 guidance after closing the sale of Ecova and the AERC acquisition. After excluding one-time gains and contributions to charity, ongoing guidance remains virtually unchanged.

Figure 64: Latest AVA Revised Guidance

Guidance	May 7, 2014 (1Q14)			Aug 6, 2014 (2Q14)			
	Low	High	Midpoint	Low	High	Midpoint	Delta
Avista Utilities	$1.68	$1.82	$1.75	$1.79	$1.94	$1.87	$0.12
Ecova (Discontin.)	$0.12	$0.16	$0.14	$1.13	$1.15	$1.14	$1.00
AERC	$0.00	$0.00	$0.00	$0.03	$0.04	$0.04	$0.04
Other	($0.03)	($0.01)	($0.02)	$0.05	$0.07	$0.06	$0.08
Consolidated	$1.77	$1.97	$1.87	$3.00	$3.20	$3.10	$1.23
Less: Ecova	$0.00	$0.00	$0.00	$1.13	$1.15	$1.14	$1.14
Less: CA Settlement	$0.00	$0.00	$0.00	$0.09	$0.09	$0.09	$0.09
Adjusted Guidance	$1.77	$1.97	$1.87	$1.78	$1.96	$1.87	$0.00
Qualitative		*"High-End"*			*"Upper-End"*		
UBSe						***$1.93***	
Consensus						***$1.91***	

Source: UBS estimates, Company filings, FactSet

Maintain PT after recently lowering by $3 to $30 for a previously reflected lower 2016 estimate and a compressed multiple of 14.2x vs 14.8x previously.

Figure 65: Sum of the Parts Valuation on 2016E P/E

Avista P/E Valuation (2016E)		**Low Case**		**Base Case**		**High Case**	
		Multiple	**$Mn**	**Multiple**	**$Mn**	**Valuation**	**$Mn**
				Peer	***14.2 x***		
Consolidated Net Income	$126	13.2 x	$1,671	14.2 x	$1,798	15.2 x	$1,924
Fully Diluted Outstanding Shares (2016E)			*60.9*		*60.9*		*60.9*
AVA Equity Value per Share			**$27.43**		**$29.50**		**$31.57**

Source: UBS estimates, Company filings, FactSet

Looking to bag some trophies in Alaska

A growing presence in the state could garner further credibility with regulators there as well.

The successful purchase of 121-year old AERC (and utility AEL&P) from the Corbus family this year is likely to make AVA a trusted potential acquirer across a region where the matchup of compatible corporate cultures is considered especially important. We believe that a rollup strategy of small coops, munis, and privately held utilities in Alaska could make a relatively safe acquisition growth strategy, although the extraction of synergies is unlikely given the long distance and relative

isolation of many communities. In our opinion, a growing presence in the state could garner further credibility with regulators there as well.

Other growth opportunities in Alaska include the possible conversion of some mining customers' diesel generators with LNG. The conversion of AEL&P's large backup diesel set to LNG is unlikely to happen though due to its low usage as an emergency provider (e.g., during avalanches when the transmission line from Snettisham hydro is knocked out).

Salix still evaluating the path forward

Avista continues to push further west.

The company's Salix LNG services and solutions business continues to evaluate opportunities which may include winning some business from Hawaiian Electric Industries shipping of LNG to the islands once they begin a long-term shift toward bulk shipping. As an indicator of the size of the opportunity, Salix owns 20% of Plum Energy, which currently does small LNG delivery deals on the order of 10K-100K gals/day. If Hawaii were to convert 100% of its oil units to LNG, the size of the import could be as much as 2M gal/day. However, we caution that the Hawaiian plan has yet to be approved and even under the plan, the full conversion wouldn't be complete until 2022-2024. Other opportunities for Salix could include marine fuel bunkering for ships sailing close to US shorelines (EPA compliance) and possibly railcar engine fuelling as well.

Exceptional hydro conditions boosting earnings this year

The Energy Recovery Mechanism (ERM) increased $3.6M in 2Q and stood at $4.9M as of June 30, with investors continuing to benefit above $4M despite sharing 75% of the excess with customers as good hydro conditions continue. Management now forecasts the ERM to end the year above the $10M threshold where 90% of further gains are refunded back to customers, a benefit of at least $0.06. As noted above, we flag that the 2H comp for ERM looks especially positive since it turned negative in 2H13 after the Colstrip outage.

In sharp contrast to the Midwest and Northeast, the Pacific Northwest saw a significant increase in Cooling Degree Days (CDDs) in July with +22% in Washington and +15% in Oregon YoY. In August when the Mountain region weather turned dramatically cooler versus 2013, Washington and Oregon again proved resilient

But mostly only indirect benefits from selling into drought-stricken California

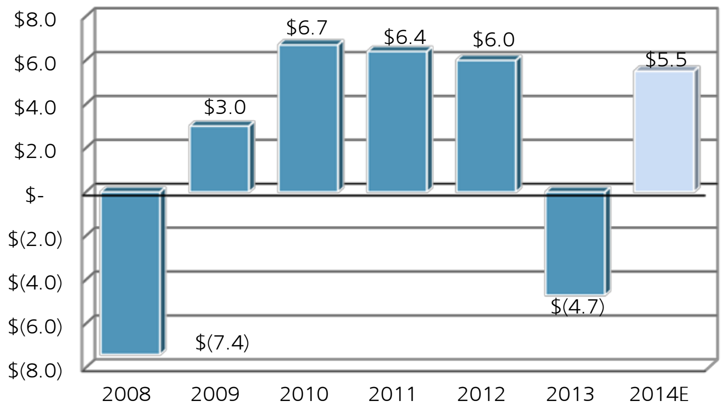
With snow melt done for the year, the ERM can still change (but probably less so) from rain in the fourth quarter. As for benefiting from the California drought, any profits made from wholesale sales off Washington hydro would flow into the ERM, so at this point AVA would only keep only a small portion – perhaps only 10% if they are in fact at the 90/10 sharing band by year-end as predicted (in Idaho, it's simpler as there are no bands - they always keep or pay only 10% of excess power profit/expense). However, in such a case, the other 90% of profits in excess of $10M would go into the ERM coffers for the future benefit of customers, which, in our opinion, could make settling the next Washington rate case in Feb 2015 a smoother process.

It's also important to recognize that the ERM mechanism could shift to a negative position for the company in any particular year. The power cost level is reset in Washington rate cases and the mechanism always starts at zero again on Jan 1,

with the company eating/keeping 100% of the first $4M of pain/gain. For example, if AVA is having a rough hydro year and needs to import power from a high-priced California market, the company would incur the first $4M of costs (and possibly more under the asymmetric sharing formulas).

Positive ERM is a catalyst for our expectation of 2014 EPS at the high-end of the range.

Figure 66: ERM Earnings Impact, 2008-2014E



Source: Company filings, UBS Estimates

For additional background on the California outlook, please review our note from Friday, **'Squeezing the Most of California's Parched Outlook'**.

Decoupling – finally – in Avista's Washington settlement

WA Decoupling mechanism implemented through fixed-fee mechanism

On 8/18, AVA announced a settlement of its Washington general rate case that was in-line with our expectations with a $15.5M rate increase ($7.0M electric and $8.5M gas), roughly half of the original request. Parties in the settlement include regulatory Staff, Public Counsel's office, the Northwest Industrial Gas Users, the Industrial Customers of Northwest Utilities, and The Energy Project. The settlement is subject to Commission approval, with public hearings to be held Aug 26/27. The 11-month statutory "suspension date" is Jan 7, 2015, which is the date that AVA's original request would automatically be implemented in the absence of a decision. Importantly, the settlement finally includes a decoupling mechanism for electric and gas in Washington from 2015-2020 that is somewhat unique in that it would be based on the allowed revenue per customer, rather than the more usual per unit of energy sold. *While we see this constructively, we see this as acknowledging the rate trend towards both a slower pace of sales growth as well as rate design shift necessary to address growing focus on distributed solar growth.*

Actual authorized ROE not disclosed in deal

ROE and capital structure are black box, but AFUDC is based on a 7.32% ROR and our estimates assume that AVA's regulated operation earns a 9.8% ROE in 2014 on 47% equity, which includes 70-90 bps of structural regulatory lag, mostly from unrecoverable costs such as directors' fees and marketing costs. This amount of lag is in-line with the high-end of company guidance for 2014 of $1.78-$1.96 (ongoing & excluding 1x gains), with another 20-30 bps included at the low end of guidance (each 10 bps ≈ $0.02 EPS).

Remain biased towards upper end of range

Our 2014 estimate is UBSe $1.93 vs consensus $1.91. Management expects to come in at the high end of the range due to the impact of strong hydro conditions and the energy recovery mechanism (ERM), which (as noted above) stands at $4.9M as of June 30 but is expected to exceed the $10M 90%/10% sharing threshold this year and add at least $0.06 to earnings net of sharing. Furthermore,

to mitigate the planned 1.4% electric rate increase, the settlement also provides for the planned rebate of $3.0M of ERM revenues from the regulatory account (cash impact only – no earnings impact). Further bill mitigation is to come from the rebate of $8.6M from the sale of renewable energy credits over an 18 month period beginning Jan 1, 2015, although this is partially offset by the expiration of other rebates at yearend. The settlement also provides for a reset of power cost rates in the ERM effective Nov 1, expected to be $6.3M higher in 2015, which would be offset by additional ERM deferral balances. Project Compass revenue requirements for 2015 (a gas customer information system, not to be confused with the proposed Northeast transmission project) are to be deferred to a future rate case after the project goes in-service.

Management expects to file its next Washington ratecase as soon as February, with frequent rate filing 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).

Management expects to file its next Washington ratecase as soon as February,

Idaho Settlement approved too

Regulators just approved the one-year settlement AVA announced on July 14 in its Idaho general rate case, leaving base rates unchanged through Dec 31, 2015. The agreement results in $3.7M of pre-tax margin for 2015, mostly from the delay of amortization of deferred O&M at Colstrip and Coyote Springs 2 from 2015 into 2016 and the deferral of Project Compass (see above) costs as well. Furthermore, the settlement allows the utility to earn between 9.5% and 9.8% ROE, with support from the deferral of any 2014 earnings test up to 9.5%. The next rate filing in Idaho cannot be filed before May 31, 2015 (for Jan 1, 2016 rates after a 7-month process).

On July 14, AVA announced a one-year settlement in its Idaho general ratecase.

Oregon filed; Alaska filing coming soon

AVA filed a rate case in Oregon on Sept 2 for a $9.1M gas increase based on 51% equity and 9.9% ROE. The company currently earns its authorized 9.65% rate of return. The statutory deadline is 10 months to review.

Management expects to file a ratecase in Alaska in either Sept or 4Q.

Pulling the rate cases together

With Avista having historical test years in most jurisdictions; it appears that the company will continue having to file rate cases virtually annually to recover ordinary capital spending. This introduces additional uncertainty into the story but the risk profile is reduced by the fact that Avista historically has settled its rate cases (see Idaho and Washington above).

Calpine Corp. (Neutral, $24)

Guidance in-line, the focus is on balance sheet deployment.

We expect a slight 3Q beat, but with the real focus on 2015 guidance – which appears inline

We project 3Q Adjusted EBITDA of **$747 Mn**, slightly ahead of consensus of $730 Mn. We think results will be largely in-line with Street expectations, reflecting a modest decline YoY already. We flag while volumes are likely to be down modestly, new additions (first full quarter of contributions from Channel/Deer Park), recent acquisitions (Guadeloupe in Texas), and higher spark spreads across many regions YoY are likely to drive a reasonable outlook despite the mild summer weather.

Figure 67: Calpine 3Q14 YoY Adjusted EBITDA estimate

3Q13A Adj. EBITDA ($Mn)	**$802**	
Revenue Type Walk	**UBSe**	*Notes*
Capacity Price Changes		
RA Payments (California)	(2)	Delta now receives RA (instead of Toll) on 2-year PG&E Deal
Non-California (PJM, etc.)	(30)	PJM Improving YoY due to MAAC/EMAAC Prices
Energy Margin		
Hedge Position	(18)	Hedges are -$1/MWh Bal of Year YoY; but more hedged , Open Sparks up
Sale of Southeast 'Six Pack'	(35)	Southeast Sale (7.5TWh), with 3Q Bias, w/ -$60 Mn for 2H14
Guadeloupe Acquisition in TX	15	Closed on at end of Feb, 2014
Deer Park & Channel	10	Began Operations in June, 2014
Los Esteros	4	First Full Quarter Contribution in 4Q13
Russell City	6	First Full Quarter Contribution in 4Q13
Total Uplift	**(18)**	Hedges are -$1/MWh YoY
Volumetric Improvement	(5)	Mild Weather in 3Q, Although Sparks Better in Most Regions[-2TWh YoY]
Net Change	**(55)**	
3Q14E Adj. EBITDA	**747**	
(Adjusted) Consensus	*$730*	

Source: Company reports and UBS estimates

Links to our relevant recent research are below:
9/30/14 Doing the Texas Two Step
8/28/14 Another Day, Another Deal
8/25/14 Deploying Capital, One Asset At a Time
8/6/14 Making the Most of Its Capital Opportunity
7/15/14 Better Than a Buyback

… And then what about the balance of the year?

We include our latest outlook for the balance of 2014 below, reflecting an updated view on 4Q14 Adj. EBITDA estimates. We flag a continued headwind on capacity price trends will be partially offset by asset additions.

Figure 68: 4Q YoY walk and implied 2014 Adj EBITDA

4Q13A Adj. EBITDA ($Mn)	$399	
Revenue Type Walk	UBSe	Notes
Capacity Price Changes		
RA Payments (California)	-	Delta now receives RA (instead of Toll) on 2-year PG&E Deal
Non-California (PJM, etc.)	(30)	PJM Improving YoY due to MAAC/EMAAC Prices
Energy Margin		
Hedge Position	2	Hedges are -$1/MWh Bal of Year YoY; but more hedged
Sale of Southeast 'Six Pack'	(25)	Southeast Sale (7.5TWh), with 3Q Bias, w/ -$60 Mn for 2H14
Guadeloupe Acquisition in TX	10	Closed on at end of Feb, 2014
Deer Park & Channel	5	Began Operations in June, 2014
Los Esteros	-	First Full Quarter Contribution in 4Q13
Russell City	-	First Full Quarter Contribution in 4Q13
Total Uplift	**(8)**	Hedges are -$1/MWh YoY
Volumetric Improvement	-	Mild Weather in 3Q, Offset by Better Hydro in California [-2TWh YoY]
Net Change	**(38)**	
4Q14E Adj. EBITDA	**361**	
(Adjusted) Consensus	*$364*	
	859	1H14 Actual
	747	3Q14 Estimate
	361	4Q14 Estimate
	1,967	**Implied 2014 Adj EBITDA (Guidance = $1.9-2.0 Bn)**

Source: Company reports and UBS estimates

What will drive shares? It's about capital allocation

Beyond the pending PJM capacity market reforms, we emphasize the focus on Calpine will remain on its use of remaining FCF of $1.3-1.4 Bn (as of 2Q14), with a remaining $800-900 Mn following its recent $500 Mn acquisition of the Fore River CCGT from Exelon in New England.

PJM remains a big story but capital allocation is the main act.

We believe management is likely to have continued execution of its share repurchase program, with our estimate reflecting a run-rate of $600 Mn/yr in our current estimates.

Acquisitions remain the burning question

We think management is likely to continue to examine a number of possibilities to grow the business with excess FCF. We think the broader Northeast market remains a potential for expansion, with an emphasis on New York and New England.

Question remains will it be allowed to participate in PJM consolidation?

Among the potential acquisition targets (few gas portfolios being marketed) is PPL's Talen portfolio as part of market mitigation. It remains unclear from our read as to whether Calpine will be able to participate given its mid-sized existing portfolio in PJM East.

More capacity in California? Details likely on SCE RFP

Management disclosed on its last call it was participating in the ongoing SCE RFP for more capacity under its Long-term procurement plan (LTPP). While no details were provided for competitive reasons, we think details could yet emerge in subsequent weeks (potentially in time for 3Q results – or the EEI conference.)

Despite the further addition of EBITDA in the state, we think management remains recalcitrant to monetize any of its assets in the region to YieldCo's. The latest contract award would likely prove suitable for a contract.

Calpine sale to Duke in Florida: Still Awaiting news

Hashing out the details of a sale? Price point remains key in FL for Calpine

We continue to await updates on negotiations between the companies on its disclosed potential sale of the Osprey CCGT as part of Duke's ongoing peaker RFP. Duke had disclosed a self-build option, but upon further reflection – and seemingly pressure from outside groups, a re-evaluation of whether to use existing assets in the state alongside new transmission investment has been introduced. We flag Duke's recent set back on its nuclear cost recovery in the state for its now defunct Crystal River nuclear project could yet imply further pressure on Duke to change its status quo proposal of a self-build. We also flag that Calpine's sale price expectations appear to have been materially reduced in order to enable a sale.

We initially estimate $200-300/kW for the CCGT

We see a further transaction in the southeast, particularly one in Florida, as bolstering the outlook for the region. Our SOP continues to value the balance of Calpine's regional portfolio on a $/kW basis.

Dual Fuel? Calpine is largely there already

Given the focus on gas asset capabilities, we emphasize Calpine's existing portfolio is largely dual-fuel enabled in the Northeast, with just 485MW gas-only of its 4.99GW PJM portfolio.

We believe investors have falsely focused on unit capabilities – and gas deliverability – as a significant source of incremental retrofit costs for companies like Calpine. While not only is the company largely compliant, we see the ability to continue to participate in the flexible market with gas-only units, with management teams effectively taking on the associated risk of performance (through the risk of greater penalties).

Among the key revisions Calpine has sought includes the ability to pursue portfolio compliance, over-compensating on certain units to offset risks on non-deliverability on others. We think such adjustments will prove palatable to a large extent.

Where is Guidance? Likely in the $1.9-2.1 Bn range

Focus on per share EBITDA growth.

Topping the $2 Bn mark, we believe management's outlook for 2015 could yet be at least $1.9-2.1 Bn (if not $1.95-2.15 Bn), seeing a $200 Mn range historically. We emphasize a particularly wide open position on 2015 on its hedge profile drives a particularly wide range in our forward expectations. Net-net, we see it as notable that management has proven able to grow not just FCF per share value yet again – but nominal EBITDA yet again. We think management will prove unlikely to offset headwinds to 2016 to nominal EBITDA, emphasizing per share growth remains positive.

Figure 69: Updated 2015 YoY Adj. EBITDA Guidance Walk – Readily expect range of $1.9-2.0 Bn

2014 EBITDA Estimate		**$1,967**	
Revenue Type Walk	**Capacity (MW)**		*Notes*
Other Capacity Markets (PJM, NYISO, ISO-NE etc)		**(28)**	*Includes ~200 MW of HEDD retirements*
New Assets			
Texas			
Guadeloupe	1,000	5	Closed in late Feb, 2014
Deer Park	200	12	Assuming Half of EBITDA when built @ 6x EBITDA
Channel	200	12	
		29	
PJM			
Garrison (Energy Only)	309	10	Just capturing increntemental Spark, O&M offset by HEDD retirements
New England			
Fore River	800	68	Closes in late 2014; Uplift details in latest note
Southeast Six Pack Divestment		(40)	
Hedges		**16**	Net of New Assets, *appears* to be slightly up
2015 EBITDA Estimate		**$2,022**	
Consensus		2,035	

Source: Company reports and UBS estimates

What about cash flow though?

We include our latest FCF projections for the company, premised on recent commodity marks below. We emphasize that management is likely to continue to harp on continued growth in its FCF growth per share. We think the company could yet peak on FCF next year, with the top end reaching $1.0 Bn. Moreover, the company appears clearly poised to hit its 15-20% FCF CAGR through the forecast period.

Figure 70: FCF and FCF/sh projections for Calpine

	2012	2013	2014	2015	2016	2017
Calpine Recurring FCF Guidance	525-575	575-775				
Non-recurring IR Swap payment	156					
Non-recurring FCF Range						
UBS FCF Est.	**564***	**677**	**791**	**948**	**844**	**795**
Mgmt FCF Guidance	550*	645-670	785-885	**900-1,000**		
FCF per Share	**1.20**	**1.54**	**1.94**	**2.49**	**2.39**	**2.44**
Mgmt FCF/shr Guidance		**1.50**	**1.85 - 2.10**	**$2.30-2.60**		
FCF *Growth* (YoY)	19%	28%	26%	28%	-4%	2%
CAGR off 2011 of $1.01 FCF/shr	18.8%	23.3%	24.3%	25.3%	18.8%	15.8%
Guidance	15-20%					
FCF Yield	**5.8%**	**7.0%**	**8.2%**	**9.8%**	**8.7%**	**8.2%**
Turbine Upgrade	(10)	(25)	(20)	0	0	0
Deer Park, TX (CT Addition)	(38)	(72)	(34)	0	0	0
Channel, TX (CT Addition)	(38)	(72)	(34)	0	0	0
Garrison, DE (New PJM CCGT)	(15)	(53)	(48)	0	0	0
York CCGT (New PJM CCGT)	0	0	(100)	(100)	0	0
Growth Capex	**(100)**	**(221)**	**(236)**	**(100)**	**0**	**0**
Projected Debt Amort/Sweeps	(120)	(140)	(180)	(190)	(200)	(210)
Remaining FCF	***344***	***316***	***375***	***658***	***644***	***585***
Asset Sales	825	1	1,530	0	0	0
Starting Cash	1,252	1,284	941	441	441	441
Ending Cash	1,284	941	441	441	441	441
Δ in Cash Balance	***32***	***(343)***	***(500)***	***0***	***(0)***	***-***
Deployable for Growth/Share Repo	**1,137**	**660**	**2,405**	**658**	**644**	**585**
Share Repurchase Placeholder	(463)	(623)	(600)	(600)	(600)	(600)
Projected Avg. Shares O/S	471	441	408	380	353	326

Source: Company reports and UBS estimates

What about EBITDA projections?

Our latest estimates are slightly lower than our prior expectations, however, remain broadly in-line with forward expectations for 2014 and 2015. We do see some downward risk to 2016 on the back of continued expiration of contracts in California, alongside Northeast PJM capacity price roll-off.

Figure 71: Updated Calpine Adjusted EBITDA Forecast

Calpine Adj. EBITDA UBSe	2012	2013	2014	2015	2016	2017	2018
West	647	676	782	743	758	758	782
Texas	371	441	373	417	418	411	441
Southeast	122	102	56	25	18	17	17
North	609	611	672	741	615	554	632
Other	-	-	30	29	30	31	31
Corporate Allocation	-	-	54	67	68	70	72
Total EBITDA	**1,749**	**1,830**	**1,967**	**2,022**	**1,907**	**1,840**	**1,974**
Guidance		*1,800-1,825*	*1,900-2,000*				
Street Consensus (10/10/14)			*1,961*	*2,057*	*2,023*	*2,047*	
Previous UBS							

Source: Company reports and UBS estimates

Where does our valuation stand?

We include our latest valuation SOP, reflecting the latest commodity marks. We emphasize investors have increasingly gravitated towards management's 'smile' arguments, as gas price concerns pervade in the sector.

Importantly, we see continued focus on gas basis compression as driving disproportionate interest in this angle of the story, recognizing Calpine's growing PJM portfolio.

Figure 72: Maintaining our price target at $24/share.

All figures in US $ million except per share data	2016E EBITDAR	EV/EBITDA Multiple			Enterprise Value		
		Low	Base	High	Low	Base	High
West	758	7.0x	8.0x	9.0x	$5,308	$6,067	$6,825
Texas	418	8.0x	9.0x	10.0x	3,343	3,761	4,179
Southeast (Remaining)	17	8.0x	9.0x	10.0x	133	149	166
North	615	8.0x	9.0x	10.0x	4,918	5,532	6,147
Other	30	8.0x	9.0x	10.0x	241	271	301
Hedge Impact (Adj. for Steam,etc.)	(33)	8.0x	9.0x	10.0x	(268)	(301)	(335)
Adj. for Commodity Margin to EBITDA	69	8.0x	9.0x	10.0x	554	623	692
Total / Implied	*1,873*	*7.6x*	*8.6x*	*9.6x*	*$14,229*	*$16,102*	*$17,975*
Subtract: Net Debt						(9,123)	
Subtract: Operating Leases						(160)	
Add: NPV of NOLs						1,171	
Add: Hedge Value						33	
Add in Further Plant-Level Value	**MWs**		**$/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					$6,898	$9,103	$11,241
Projected Number of Shares Outstanding (2016E)					380	380	380
Equity value per share					$18.13	$23.93	$29.55
Implied $/KW					545	617	689
FCF (pre-growth) for 2016						831	
Implied FCF Yield						9.1%	

Source: Company reports and UBS estimates

Consolidated Edison (Neutral; $59 PT)

Signs continue to point towards more certainty for ED in '15 but key datapoint timelines frustratingly lack visibility. Hope springs eternal after the election.

Quarter will likely decline YoY but it is unlikely that will dip by the magnitude the Street is forecasting.

Consolidated Edison is estimated to report 3Q14 EPS of **$1.43**, down versus 3Q13 but still notably higher than consensus ($1.38) which largely has remained static since second quarter results. The quarter looks quite similar to 2Q14 with D&A and property tax drag of $0.05 remaining the largest factor with a decline in usage also contributing to weaker results. Development should show some improvement based upon the accelerated rate of spending but that only serves to offset continued declines at Solutions where retail margins firming somewhat should slow the rate of decline versus earlier quarters. While retail could prove weaker than we estimate, we still anticipate a modest beat versus consensus.

Could ED bump guidance in back-to-back quarters?

Con Ed increased the low end of its guidance range $0.05 with second quarter results in early August and the current range is $3.70-$3.85 versus UBSe/Consensus of $3.82/$3.80. With our expectation of adjusted EPS to be above the midpoint of the range by close to a nickel, **management could opt to increase its guidance range a further $0.05 to $3.75-$3.90**. Based on our third quarter earnings estimate, we calculate TTM EPS of $3.93 and even with similar earnings declines YoY in the fourth quarter the FY14 earnings would be above the current guidance range ($3.88 vs $3.75). Quarters with back-to-back EPS guidance increases are not unprecedented and ED did the same thing in 2Q10/3Q10.

With respect to 2015 guidance, we do not foresee a change to ED's typical pattern of releasing forward year guidance early in the calendar year (~February).

Figure 73: 3Q14 Earnings Walk

ED 3Q13	$	1.48
Usage		(0.03)
Wheeling contract with PJM		0.01
Oil-to-Gas Conversion		0.01
Interest true-up elimination		0.01
O&M - incentive comp and health expenses		0.01
D&A and prop taxes		(0.05)
Total CECONY		**(0.04)**
Total O&R		**-**
Competitive Energy Businesses		
Solutions (excludes MTM)		(0.01)
Development (excludes LILO)		0.01
Energy		-
Total CEBs		**-**
Parent		**-**
ED 3Q14E	**$**	**1.43**
Consensus	*$*	*1.38*

Source: Company Filings, FactSet, UBS Estimates

Links to our relevant recent research are below:

[10/6/14 Dropping the Danskammer on New York]

[8/8/14 Light At the End of the Regulatory Tunnel]

[6/5/14 Painting a Turnaround for 2015?](#)
[5/9/14 Steamy Winter in the City](#)

After Seven Months of NTSB Wait, We Wait Some More

Harlem explosion clarity remains elusive for now

The National Transportation Safety Board (NTSB) is leading the investigation into Con Ed's March 12 gas explosion that killed eight in Harlem which has Con Ed, the city of New York, and New York Public Service Commission (PSC) all as parties to the investigation. Previously we had expected the NTSB statement of facts (no conclusion) in the September/October window with a more important recommendation around 1Q15 but with that timeline having passed, we lack concrete direction here. Given confidentiality, there has been uniform silence from all parties to date. Importantly, being a party on the case means that the entities are privy to the proceedings with the ability to fact-check, etc. with the caveat being that ability to opine publicly is limited. Consequently, we would not expect to hear any material updates from any of the parties ahead of the NTSB's investigation conclusion. We note that the street where the accident occurred was tested once in 2013 and twice in 2014 (February 10 and 28) with no leaks found. Given the qualifications placed on the PSC and other parties to the investigation, it does not appear likely that the PSC will opine on the tragedy at this time and is not opening a docket to investigate at this time.

Statement of fact report from NTSB had been expected by September but that timeframe has gone out the window.

Currently mgmt is working on a pilot program to test for gas leaks more frequently

ED has been taking proactive steps to prevent such actions in the future and has already agreed to replace ~65miles of cast iron pipe per year as part of its recent rate case settlement and there is the possibility to accelerate the spending although no decision has been made here. Currently management is working on a pilot program to add gas testing capabilities to its ordinary monthly voltage testing that would increase gas leak testing from annual to monthly at a 'very low incremental cost'. Con Ed will also work with NYC to coordinate cast iron gas pipe replacement with the city's water pipe replacement in order to keep costs in-check.

REV Gradually Moving Forward

NY PSC proposal to support expansion of distributed energy resources

PSC straw proposal with recommendations on the REV initiative, which addresses how regulation can be modified to enable utilities to manage integration of distributed energy resources

The NY PSC Staff filed a straw proposal on August 22nd with subsequent comments as part of the Reforming Energy Vision (REV) docket. The REV initiative underlines our own expectation that distributed PV solar will continue to expand in the northeastern markets, and calls for regulatory support for peripheral investments.

Networks capex in the state are being catalyzed by specific characteristics of the NY market such as increasing 'peakiness' of the demand curve, and a generally aging infrastructure (~14GW of non-hydro generation assets are more than 40 years old) – and the case for regulatory support needs to be seen against a backdrop of low load growth (projected to be 0.16% per year through 2024).

Proposals recommend exiting utilities can serve as Distributed System Platform

Should the DSP be an incumbent utility or an independent entity? Proposals say existing utilities should be the DSP

Under the REV, the PSC is investigating how existing regulation can be modified so as to allow power utility companies (both regulated and unregulated participants) to be compensated for managing their infrastructure to complement distributed energy resources (DER). To support the expansion of DER, the proposals support the formulation of a Distributed System Platform (DSP) – 'an intelligent network platform that will provide safe, reliable and efficient electric services by integrating

diverse resources to meet customers' and society's evolving needs'. Some key policy recommendations made by the PSC staff in the proposals – which we find interesting - include:

- Existing utilities in the market should serve as the DSP, and their long-term status as DSP providers should be subject to performance reviews
- DER providers that satisfy Commission requirements should have access to individual customer usage data (who will have an opt-out option)
- Utilities can be allowed to own DERs too subject to conditions, and an approved plan
- Market power protections should be put in place if utility affiliates participate in DSP markets within the service territory operated by their parent company
- Steps taken in the near term to develop demand response tariffs for all service territories, including tariffs for storage and energy efficiency
- the Commission should exercise oversight of DER providers to protect consumers and reliability of service
- A benefit-cost framework should be defined appropriate to three different purposes: (1) utility DSP implementation plans; (2) periodic utility resource plans; and (3) pricing and procurement of DER; and
- As a transition toward market-based approaches to increase levels of efficiency and renewables, utilities should integrate energy efficiency into their regular operations and should take responsibility for procurement of Main Tier renewables.

Although we expect any actual regulatory outcome to take shape over the course of *years*, the current proposals focus on more near-term measures required to move towards the final goal. In the immediate term reply comments will be accepted until October 24th with a second technical conference on policy questions November 6th.

Not yet at the starting gate for Track 2.

Unlike the REV Track 1, REV Track 2 (generic policy decisions on design) has yet to get started as the initial PSC Staff options paper was not filed by the October 3rd target; the next key date had been the Staff straw proposal by January 30th. Without an updated schedule this puts additional risk on the entire timeline which targeted comments through March 2015 and a PSC policy determination in 2Q15.

Can the Utility 2.0 get off the ground? Starting with 1.5

While we increasingly view the REV 'Utility 2.0' compact proposed by the NY PSC as a net benefit to utilities (despite their more cautious attitudes), we believe significant implementation hurdles remain. Perhaps most notably, we sense a palpable sense of skepticism from a wide array of constituents over a seeming 'over-reach' of the PSC in terms of setting a wide ranging agenda.

The question remains what could the Utility 2.0 initiative include? We believe a lot is on the table. While likely the more controversial and slow-moving aspect of the reforms, we see the potential to accelerate capital spend at CECoNY on the back of reforms designed to build out 'behind-the-meter'. As an interesting gating item, we see a potential for a renewed discussion on smart meter rollout, seeing the city opted to forgo installation as too costly in 2006.

More broadly, we look towards whether the REV structure will lead to a long-dated rate deal in next year's CECONY rate case as part of efforts to emulate the UK's rate experience.

Is ConEd the guinea pig on the new rate model?

We understand the PSC continues to aim to implement new rate filings under a more RIIO (UK) model beginning with rate cases next year; ConEd's New York case is likely to be the first filed under this new structure (ambitiously); however, the recent delays in the process could impact timing. If successful, we believe implementation would be warmly received by the investment community with the goal of a protracted stay-out, with explicit (and well delineated) performance objectives. The PSC has a stated goal of implementing this new rate structure across all of the states' utilities by ~2017. We see the RIIO transition as among the easiest reforms to implement, reducing the risk profile of the utilities if done right (and again, given NY's more strained history with its utilities, we emphasize if done right). This could drive a re-rating higher in what has historically proven a challenging regulatory dynamic.

A long-term rate deal (up 5-to-8 years?) would likely be positively perceived by investors

Con Ed proposes 'Utility 1.5', a step towards 2.0

In July Con Ed filed a proposal with the NY PSC for a Brooklyn/Queens Demand Management Program (BQDM) with the hope of investing $200Mn into customer demand management programs to defer the need for an estimated ~$1Bn substation. ED is prepared to spend $25Mn from the currently approved demand side management (DSM) program (largely under competitively solicitations) but is requesting approval to spend $200Mn on demand management. Based on Con Ed's current projections the Brownsville No. 1 & 2 Brooklyn substations are overloaded necessitating the aforementioned new substation by 2017 and related sub-transmission feeders. Currently management believes that it will be able to meet the higher load in 2014-2015 with "operational measures" but foresees a shortfall after that point.

ED hopes to spend $200Mn short-term to defer need for $1Bn substation in intermediate-term

If successful the demand management programs could shave 52MW of demand and utility investments (capacitors, load transfers, and other investments) would account for 17MW (undisclosed capital cost), by 2018 thereby offsetting the projected 69MW of excess load forecasted.

- **Customer Side:** 41MW for $150Mn ($3.7Mn per MW); 5 year recovery via customer surcharge
- **Utility Side:** 11MW for $50Mn ($4.5Mn per MW); 10 year recovery via customer surcharge

Projected Load Increase: 69MW
Offset by:
41MW of Customer DSM
11MW of Utility DSM
17MW Utility Investment

Additionally management is requesting a 100bp incentive on investments based upon achievement of benchmarks to spur spending in this area. Net cost savings would be shared 50%/50% between customers and Con Ed, as defined as cost of the original new substation less collections from the BQDM program.

Incentive mechanisms with cost benefit sharing could be the model of 'Utility 2.0'.

The proposal focuses on Brooklyn and Queens due to the population growth in those regions and the unique nature of its load that differs from other regions of Con Ed's service territory (~12 hour peak from 12PM to 12AM). ED's proposal is a step towards the PSC's Reforming the Energy Vision (REV) model discussed above. The docket was notably silent until the beginning of October where the IPPs of New York and the City of New York have provided comments. While the generators oppose ED owning any form of generation, even DG, the City is concerned about the rate impact primarily (a key topic of late especially with the creation of the LHV Zone). The docket lacks a concrete timeline (following a similar theme as above) with the initial comment period now closed.

BQDM docket remained eerily quiet until early October when the natural intervenors commented.

Dockets: 14-M-0101 (REV), 14-E-0302 (BQDM), and 13-E-0030 (ED)

AC Transmission Docket Still Exists…

Management confirmed that there has been minimal progress on Con Ed's AC Transmission proposal or any other Indian Point contingency projects outside of the "no regrets" plans; we understand work on this project is anticipated to pick up once again following the November elections. In February the PSC instructed the three bidders to re-submit their proposals using existing right-of-ways (largely owned by ED) but overall it looks like progress has stalled here, again looking like no real projects will pick up steam ahead of the November election. Recent comments on the docket have focused on cost recovery, allocation, risk sharing, etc. but do not bring us closer to having direction.

Looking for developments late this year/early 2015, post-election

Moreover, with both the PSC and NYISO unsuccessful in stemming implementation of the Lower Hudson Valley (LHV) capacity zone, we believe efforts to alleviate the congestion in the zone could yet add to efforts to expedite new transmission projects in the state.

Dockets: 12-T-0502 (AC Transmission) and 12-E-0503 (Indian Point Contingency)

Solutions and Unregulated

Could Management turn around the retail business?

Among the key elements to a further re-rating in shares is the turnaround of its retail business, which could yet see its contribution flip from a negative contribution (seemingly -$0.01 in 2013, but likely a wider loss in 2014), to a positive. At a minimum, this would augment the continued steady EPS contributions from its Development business. While a scaling back of the retail business would not only limit a drag in results, but could readily lend itself to a profitable business if successfully implemented as part of a turn-around in the business as part of affiliate sales under the aforementioned Utility 2.0 model. We believe the retail model is poised to transform (or at a minimum scale itself back) with margins at the very least firming. Net-net, we see this part of the overall potential opportunity from reforms in New York.

But our deeper look at unregulated businesses yields questions on growth

While management appears eager to see its unregulated businesses reach ~5%-10% (~$0.20-$0.40) of consolidated EPS between Solutions, its retail business, and Development, its contracted business, we see a challenging road to achieve this objective off the ~$0.04 we project in 2014. Following meetings with company executives this summer, we don't think this is a source of much upside for the company. Rather, we fear Solutions and Development could see more limited growth in coming years and continue to disappoint. Having failed to win the LIPA services RFP to PSEG and seeing an increasingly competitive marketplace for further solar opportunities, it remains unclear from where Development will source further deals. We perceive nearer-term priorities as bringing its retail business back to a breakeven, but the upside is clearly not in 'energy', but in executing in cross-selling products and distributed gen opportunities. As for Development, we sense a slowing growth opportunity as utility-scale projects have slowed; that said, management appears confident that it has a pipeline to drive (some) growth; net-net, we don't expect too much from this business, with +$0.02/sh YoY growth in 2015 likely at the high end of expectations.

While retail margins appear to have bottomed, real improvement appears premised on diversification and re-defining the business plan

In exploring this question with management, it appears the company is most intrigued by potential C&I opportunities around Distributed Generation, seemingly as a function of New York's interest in pursuing wider-scale implementation of micro-grids and other 'behind-the-meter' solutions. Similarly such opportunities could yet be open to utility (rate-base) investment as well, according to our discussions with the PSC (part of a quasi-re-regulation of the state, in our view).

Further afield, we sense the Development business as open to pursuing contracted Hydro (run-of-river) and Battery solutions to delivery on further growth. Generally speaking the company has targeted levered IRRs in the mid-teens on investments.

Development opportunity remains as ED

Development has developed utility-scale solar projects in recent years

ConEd Development has in recent years benefitted from a series of utility-scale solar projects developed in California, largely splitting projects with Sempra (SRE). Following its latest announcement to acquire a 50% stake in SRE's Copper Mountain III project, we see line of sight to continued EPS growth worth ~$0.02/sh. We understand management intends to use less leverage than many conventional solar developers, in an effort to keep its consolidated metrics roughly in-line with its utility capital structure (~roughly 40% levered); we perceive this as a structural disadvantage vs. industry peers willing to employ substantially greater leverage (~70%). How can ConEd still be competitive? It appears the answer is its own organic tax appetite, in lieu of peers seeking tax equity to finance projects (particularly now without the benefit of CITCs on solar deals).

The question remains what will it focus on next?

New York solar: Ready for the spotlight?

ED views NY solar as still largely uneconomic

Despite the NY PSC granting approval for O&R and CECoNY to install 100MW of solar, ED has done "next to nothing" on the front as it is <u>not economic</u>. We have heard from solar supporters and developers that areas of New York, particularly Long Island, are ripe for solar growth, but Con Ed was quick to downplay the opportunity. <u>Management did note that the situation is getting better in New York but is still not at the tipping point yet.</u> Moving on to the topic of Con Ed Development, management noted that the increased capex from ~$100Mn to ~$300Mn per year was done largely to make the placeholder more realistic but stressed that it is still a placeholder and it is under no pressure to meet that level of spending if the projects are not there. Con Ed Solutions will still continue to grow with the segment acquiring and developing assets but will remain a modest business with no aspirations to grow dramatically faster than the regulated pieces.

Appears unlikely to materially expand solar investments under current construct

Question outstanding is whether there will be other palatable investments from new structure?

Capex increased with 2Q but more traditional solar versus New York

Sempra's potential YieldCo could impact ED's ability to share in future projects.

ED increased its 2014 capex estimates at its competitive energy business from $243mn to $470mn (gross basis) to fund renewable developments related to a purchase of interest in Copper Mountain (CM) Solar 3 Holdings (which owns a under-development 250MW solar) project in Nevada. <u>We believe ED is a key candidate for the sell-down of SRE's announced CM4 project</u>; the latest capex update maintains a further placeholder for acquisitions in the year.

~$1Bn of Debt Could Be Coming In Next 75 Days

CECoNY could come to the debt markets for ~$1Bn in the next few months or it could defer until next year again.

No equity was needed in 2014 (neither external nor DRIP) but management guided to planned debt issuances of $1.5-2.0Bn to finance its $2.8Bn of capex. For the most part the capex needs and debt issuance will be at CECoNY where $475Mn of debt matured in 1H14. The only debt issuance in 2014 came in March when CECoNY issued $850Mn of thirty-year debt at 4.45%. This leaves ~$1Bn of debt

that could come in the balance of the year. Next year $350Mn of CECoNY debt (5.375%) is maturing in December with ~$140Mn of O&R debt maturing throughout the year

Last year management did not issue as much debt as it had guided to (~$700Mn latitude) but its CECoNY equity ratio has crept back up to 52% as of 6/30/14 (authorized ratio is 48% but are allowed to earn up to 50%).

Valuation: Increasing Price Target $4 to $59

Increasing our Price Target $4 on higher utility peer multiple.

Our Con Ed valuation is based on 2016E undiscounted P/E multiple which has expanded to nearly 15.0x from 14.0x previously. We continue to view shares as fully valued, or potentially a bit pricy, in the absence of regulatory reform and clarity on the NTSB Harlem investigation. It appears that efforts on the Energy Highway/Indian Point contingency could resume following the election which could be another catalyst for shares (after a year plus of stagnation on the docket).

Despite the elevated level of uncertainty, ED is trading at 15.6x (2016E), a slight premium to regulated peers at 15.2x on the latest mark. While we had thought there could be some overhang on shares from the investigation, it seems that the uplift from the potential 'Utility 2.0' reforms is at least counteracting this negative. In August we removed our 5% discount to peers as we see the regulatory process as encouraging for shares.

Figure 74: Updated ED Valuation

Consolidated Edison Valuation			
Regulated 2016 P/E Multiple		*14.9x*	
	Low Case	Base Case	High Case
2016 EPS	$ 3.95	$ 3.95	$ 3.95
x P/E Multiple	14.5x	14.9x	14.5x
Discount	-5%	0%	5%
Valuation	**$54.44**	**$58.89**	**$60.17**

Source: Company Filings, FactSet, and UBS Estimates

Figure 75: Updated ED EPS Estimates

	2012A	2013E	2014E	2015E	2016E	2017E
Consolidated Edison of New York	**$3.45**	**$3.33**	**$3.55**	**$3.67**	**$3.74**	**$3.92**
Orange & Rockland	**$0.21**	**$0.23**	**$0.22**	**$0.21**	**$0.22**	**$0.22**
Other	**$0.08**	**$0.22**	**$0.03**	**($0.02)**	**($0.01)**	**$0.03**
Consolidated	**$3.73**	**$3.79**	**$3.81**	**$3.86**	**$3.95**	**$4.17**
% Growth		*1%*	*1%*	*1%*	*2%*	*5%*
Prior estimates	$3.73	$3.79	$3.78	$3.85	$3.94	$4.14
Guidance			**$3.70-$3.85**			
Consensus		$3.80	$3.76	$3.88	$4.04	$4.21

Source: Company Filings, FactSet, and UBS Estimates

Dominion Resources (Buy, $82)

Miss by a dime for 3Q, but forward estimates rise a dime for stronger power pricing

We expect D to report **$0.89** for the quarter vs consensus $0.99 and guidance of $0.90-$1.05. The miss is largely due to mild weather, with -$0.03 of July impact already previewed by management during the 2Q call. August was also exceptionally mild for which we estimate another -$0.04 hit, while September was more or less normal. This -$0.07 hit is partially offset by an incremental improvement of +$0.04 to normal from mild weather last year, but that was already previewed and baked into management guidance. Also in the guidance is a -$0.07 impact at Dominion Energy's gas transmission business from the absence of a 1x gain on the drop-down of the TL-388 pipeline into Blue Racer in Sept 2013. Merchant generation improves +$0.02 vs the 6-day outage at Millstone last year, but this is offset by a penny less earnings at Retail after the sale of the electric business earlier this year. Higher interest also reduces earnings -$0.02.

While we expect a dime miss for 3Q, a rise in New England power prices in recent weeks raises our forward estimates a dime. Maintain $82 PT and Buy rating.

Figure 76: D 3Q Walk

3Q13A	**1.00**
Weather normalized	0.04
Weather 3Q14	(0.07)
VEPCO (weather normalized)	
Elec Dist	(0.01)
Elec Trans	0.02
Utility Gen	0.02
Regulated Gas (weather normalized)	
Gas Dist	(0.00)
Gas Trans	(0.08)
Merchant Gen	0.02
Dominion Retail	(0.01)
Interest	(0.02)
Corp & Other	(0.00)
Dilution	(0.01)
3Q14E	**0.89**
Consensus	***0.99***
3Q14 Guidance	***0.90-1.05***
2014 Guidance	***3.35-3.65***

Source: UBS Estimates, Company filings, FactSet

With TTM at $3.35 using our 3Q estimate of $0.89, we expect management to reiterate guidance of $3.35-$3.65 for 2014 (vs UBSe $3.48 and consensus $3.49), especially considering the improvement to New England power prices in recent weeks (although most of Millstone's 2014 output is hedged). We are raising our 2015-2018 estimates for a higher New England forward curve of roughly $5.50/MWh. Having skipped an analyst day this year, we expect management to provide a positive update to its 5%-6% long-term earnings growth rate at the next analyst day in February 2015. With many balls 'still in the air', we look towards a February update in which management will summarize its long-term EPS and dividend outlook, among several other datapoints (likely pushing out this expectation through at least the 5-year 2019 view, consistent with that latest capex budget). Currently we estimate a ~6.9% 2014-2019 EPS CAGR and would anticipate an upward guidance revision to the 6-7% range. Catalysts potentially not fully baked into the plan include traditional regulated development as it assesses the need to replace coal generation later this decade. In summary, we reiterate our expectations for an EPS growth rate that could yet have an 8%

Having skipped an analyst day this year, we expect management to provide a positive update to its 5%-6% long-term earnings growth rate at the next analyst day in February 2015. Currently we estimate a ~6.6% 2014-2019 EPS CAGR and would anticipate an upward guidance revision to the 6-7% range. EPS growth could yet have an 8% estimate at the top end.

estimate at the top end of the band when fully factoring the company's latest updates through the February Analyst day as well.

Our sum-of-the-parts price target remains $82, with the improved commodity outlook offset by a lower average 2015E peer utility P/E multiple. While Dominion looks pricey on a P/E basis, we believe that investors will be forced to shift their valuation methodology away from a straight P/E multiple as ~35% of the company is valued on an EV / EBITDA basis (ex. Merchant Power) a potent factor that could drive outperformance in the back-half of the year.

Figure 77: 2014 Guidance vs 2013 Actual Results and UBS 2014E-2018E

2014 Guidance vs 2013 Actual Results and UBS 2014E										
Estimates by Segment (EBIT) using ABS										
		FY14 Guidance			UBS					
VEPCO	2013A	Low	High	2014 Mid	2014E	2015E	2016E	2017E	2018E	2019E
Electric Distribution	542	590	615	603	604	664	703	724	739	754
Electric Transmission	402	460	480	470	428	475	521	555	587	618
Utility Generation	1,293	1,435	1,485	1,460	1,456	1,525	1,578	1,658	1,682	1,707
Virginia Power - Corp Adjusted	-	-	-	-	-	-	-	-	-	-
VEPCO Adjusted EBIT	**2,237**	**2,485**	**2,580**	**2,533**	**2,488**	**2,664**	**2,803**	**2,937**	**3,008**	**3,079**
Regulated Gas Ops										
Gas Distribution	242	235	245	240	240	266	288	310	331	351
Gas Transmission (Incl. Caiman)	834	780	810	795	808	891	1,001	1,007	1,105	1,107
Total Regulated Gas	**1,076**	**1,015**	**1,055**	**1,035**	**1,048**	**1,157**	**1,289**	**1,316**	**1,436**	**1,458**
Merchant Generation	341	315	360	338	340	522	541	625	771	850
Previous Merchant Generation	*341*	*315*	*360*	*338*	*340*	*462*	*439*	*527*	*674*	*748*
Dominion Retail	115	55	65	60	62	62	62	62	63	63
Corp & Other	(45)	(35)	-	(18)	(10)	(1)	68	418	441	446
Total Adjust EBIT	**3,724**	**3,835**	**4,060**	**3,948**	**3,928**	**4,403**	**4,762**	**5,359**	**5,718**	**5,895**
Interest expense	870	935	925	930	919	956	994	1,059	1,259	1,263
Income Taxes	950	950	970	960	957	1,120	1,244	1,419	1,472	1,529
Non-controlling Interests	23	25	15	20	20	20	20	20	20	20
Operating Earnings	**1,881**	**1,925**	**2,150**	**2,038**	**2,032**	**2,307**	**2,505**	**2,861**	**2,968**	**3,083**
Shares Outstanding	580	584	582	583	585	589	599	613	625	629
EPS	**3.25**	**3.30**	**3.69**	**3.50**	**3.48**	**3.92**	**4.18**	**4.67**	**4.75**	**4.90**
Previous UBS Estimates					**3.48**	**3.85**	**4.07**	**4.55**		
Formal EPS Guidance Range		**3.35**	**3.65**	**3.35-3.65**	***3.35-3.65***					
Guidance of 5%-6% growth off 2011 3.05 base minus 0.04 for elec retail				**3.53**	**3.53**	**3.73**	**3.93**	**4.15**	**4.38**	**4.62**
Growth Rate of UBS Estimates						**12.6%**	**6.8%**	**11.6%**	**1.8%**	**3.2%**
Consensus (9/26/14)					**3.49**	**3.74**	**3.91**	**4.17**		

Source: UBS Estimates, Company filings, FactSet

Capex updates: adding it all up yields a rosy outlook.

Dominion announced an incremental annual spend of $0.8bn per year compared to their last plan (the new plan includes an additional forecast year 2019 but the incremental capex is also impacted by new projects that add to each year out to 2019). The table below shows the change between the old plan and the new. Importantly, this excludes new pending projects such as the Supply Header project, for which Dominion is likely to gain sufficient clarity later this year to move forward with development (~$500 Mn spend). Moreover, upsizing of newly contemplated Atlantic pipeline is excluded.

The Southeast Solution: The Atlantic coast pipeline and supply header

The first new project is a 45% stake in the $4.5-5bn (ex-finance costs), 550+ mile long, 1.5bcf/d capacity Atlantic Coast pipeline. Dominion's 45% share in costs will be ratable. We believe the capacity has potential to increase (pipe is expandable to 2-2.5bcf/d) given our expectation for gas demand to ramp up further. The fact that the company has had an open season even after 92% of capacity is already subscribed also signals possible expansion. FERC pre-filing is fall 2014, with a FERC application fall next year; once approved by FERC (~summer 2016), the

pipeline should be operational by late 2018. The table below shows the ownership structure for the Atlantic Coast pipeline. Amongst the owners, Dominion is in charge of constructing, operating and managing the pipeline.

Figure 78: Ownership of the Atlantic Coast Pipeline

The Atlantic Coast Pipeline JV	
Dominion Resources	45%
Duke Energy	40%
Piedmont Natural Gas	10%
AGL Resources	5%

Source: Company sources

And how about a gathering network to go along with it?

Secondly, Dominion announced a complementary 100% owned, ~$500mn, 1.0-1.5 bcf/d "Supply Header" project which will be used to gather the gas, compress it, and bring it to the Atlantic Coast pipeline. An opens season for the header is planned for this fall. Capacity for the header is expandable to ~2.5bcf/d levels as well. The project will allow for more access to Marcellus and Utica gas supplies. Although we don't see the pipeline itself as competition to NEE's MVP pipe, we believe the header can be in direct competition. Company expects the header to be operational by late 2018, along the time the Atlantic Coast pipeline starts service. We flag this ~$500 Mn project would similarly drive 'chunky' EPS growth in ~2019 (following a November 2018 in-service).

We think both these projects are well supported by increasing Marcellus and Utica gas supplies. Dominion noted Wood Mackenzies' increased 2025 forecast production from ~23 bcf/d (in their 2013 forecasts) to an expected ~30bcf/d (in their revised forecasts made in 2014). The pipeline should be able to serve the heating/industrial and also power generation demand (increasing, owing to coal shutdowns) arising in Virginia and parts of Carolina.

Regulator and policy support for such investments in the Southeast has also heightened after the Polar Vortex events in the last winter. For such projects, (with project financing at the JV level during construction) we would expect Dominion to earn returns in the mid-teens.

Upside to the Atlantic Connection pipeline too.

Following disclosures earlier this month that Dominion and other parties had received ~90% of necessary volumetric commitments to move forward with their proposed Atlantic Connection pipeline, we believe there is likely upside to the contemplated 1.5 bcf/d project. In particular, we suspect the 42" inch pipeline project could yet have plants to be upsized to 2.0-2.5 bcf/d prior to its in-service in late 2018 as regional utilities continue to contemplate their gas needs. Moreover, we suspect some additional producer volumes could yet coalesce around the project – and its target markets of Eastern Virginia and Eastern North Carolina.

Could yet extend the Atlantic pipe too.

<u>We believe management could yet look to extend the pipeline down further from NC, into SC and even GA</u> in future expansions to address continued coal-to-gas switching. We see this project as uniquely benefitting from the Carbon 111(d) regulations due to their disproportionate ask of Southeast coal-to-gas switching.

A second bite at the Artificial Island project – Dominion is key player

Dominion, along with Transource (AEP and GXP), PSE&G, and LS Power all submitted revised and final bids into PJM's first FERC 1000 competitive transmission project solicitation this month. Although PSE&G had been chosen the winner in June, stakeholder concerns over cost capping and overruns has resulted in a second look at competing bids from these four finalists. All of the new final bids now include some form of cost cap except Dominion, which relies upon its track record and right- of-ways as support for cost control rather than an explicit capping mechanism. For further details, see our 9/26 note The Final Four on the Artificial Island.

Figure 79: "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

Solar now stands at 275 MW after California acquisitions

Dominion acquired the 24MW Cottonwood solar project (located in Kings, Kern and Marin Counties, California; and expected to be operational by 1H15), and the 18MW Catalina Solar 2 project (in Kern County, California; expected to be operational by 2Q15), from EDF Renewable Energy. Both the projects have secured long term PPAs (Cottonwood: 25-year PPA; Catalina: 20-year PPA), interconnection agreements and EPC contracts. Both are expected to qualify for federal ITCs; the company has already articulated a clear preference for solar over wind given the upfront tax benefits. These latest announcements follow recently announced new solar utility scale development of ~150 MW (selling to utilities under long term 15-20 year PPAs), which was on top of the 250MW planned earlier. We expect most of Dominion's solar focus to continue in California.

The company has dipped its toe into rooftop solar (~3MW) but appears to be largely protected from distributed generation given its (1) below average residential bills; and (2) relatively high T&D fixed component of the bill (potentially ~50%+). On the wind side, Dominion continues to lease offshore wind but has no imminent development plans given the significantly higher cost. Nevertheless, the company is participating in a joint offshore wind test program with the Department of Energy, although there's no plan to pursue that commercially. Furthermore, management would only consider ratebased projects backed by public policy in any case.

Update on long-term outlook would necessarily involve view on VEPCO

We believe management may yet be looking to pro-actively address its VEPCO biennial review process again to minimize over-earnings risk. Further legislation to adjust the mechanism/process could minimize even the distant risk of an over-earnings risk in the ~2019 period. If successful, this could cement the company's comfort in raising growth projections through the period that includes this potential reset.

While VEPCO has earnings certainty for the investment horizon, it could look to cement even more.

DTE Energy (Neutral; $78)

In-line 3Q as mild weather offsets P&I growth and reduced O&M

Weather is the story, with an unusual double whammy of mild weather and storm expense reducing earnings by -$0.13.

We expect DTE to report **$1.10** vs consensus $1.13, with the somewhat unusual double whammy of mild weather and storm expense reducing earnings by -$0.13. This offsets the removal of -$0.03 trading losses last year (the company excludes trading results from guidance as it looks to exit the business) and +$0.03 of growth this quarter at Power and Industrial as management guides to a $5-$15M improvement overall in 2014. Growth at Bluestone of $8-$16M this year should translate to a +$0.02 improvement in 3Q. Weather normalized utility growth helps a penny, complemented by +$0.02 from pension expense reduction ($10-$15M this year).

While we have not changed our estimates, our PT comes down $2 to $78 for a lower average 2016E utility peer P/E multiple. Maintain Neutral.

The TTM now sits at $4.53 using our 3Q estimate of $1.10, well above guidance of $4.20-$4.40 for 2014. Earlier in the year, management described having a $0.25 "weather contingency" built into estimates after the strong winter results. However, given the mild summer so far, no "reinvestment" expense (normally happens in 4Q) is expected to occur this year. Unless the weather hit this summer is significantly larger than we anticipate, we would expect 2014 guidance to be increased by as much as dime while still maintaining a healthy contingency for the 4Q. Maintain Neutral.

With DTE having skipped an analyst day this year, we expect an early look at 2015 guidance at the EEI conference, along with extended looks at capital investment and operating earnings through 2019. For 2015, we expect management to strip out this year's 1Q weather benefit and increase the current guidance by the long-term projected growth rate of 5%-6% to a range of $4.45-$4.65 vs UBSe and consensus $4.60.

Figure 80: DTE 3Q Walk

1.13	**3Q13A**
Unregulated Businesses	
P&I	
0.03	Guidance $75-85M for 2014 vs. $70M in 2013
Trading	
0.03	Subtract out last year's -0.03 and assume zero Elec trading losses offset gains from gas trading ("balanced portfolio")
Midstream	
0.02	Bluestone growth. $78-$86M guidance for 2014 vs $70M in 2013
Regulated Utilities	
0.01	Weather normalized load growth 0.0%-0.5% in 2014
(0.06)	Incremental storm expense - Had some summer storms with more than double the customer impact than 3q13
(0.06)	Weather Impact at Detroit Edison
(0.01)	Weather Impact at MichCon
0.02	O&M $10-$15m pension reduction in 2014
0.00	O&M Reinvestment - most happens in 2H, weighted to 4Q
0.00	Revenue decoupler amortization - was delayed into 2015
0.00	Parent & other -$49 to -$45M vs -$44M in 2013
(0.00)	Dilution
1.10	**3Q14E**
1.13	*Consensus*
4.20-4.40	*2014 Guidance*

Source: UBS Estimates, Company filings, FactSet

All systems are go with Nexus; partnership with Enbridge being negotiated

Management recently characterized themselves as "very enthusiastic" about the project, increasing the capacity on the pipeline to 1.5bcf/day from 1.0bcf/day and surpassed its 80% firm commitment criteria for the project. DTE also reiterated that they are "very, very optimistic" that the pipe will be completed in 2017. The project is now expected to meet the "majority" of the $20Mn of 2018E operating earnings 'white space' for the gas segment. The key question now becomes whether DTE and Spectra Energy could increase their ownership levels from 33% currently contemplated in the guidance with Enbridge potentially left on the outside looking in. The partnership agreements are currently being negotiated.

Despite investor skepticism, Nexus finally looks fully locked-in.

More stringent environmental standards set to push DTE utility capex higher

At AGA, DTE released an extended utility capex projection of $1.3B-$2.0B annually from 2019-2025 (increase of hundreds of millions per year at the midpoint from the current five year plan through 2018) and announced with 2Q earnings that it sees the amount closer towards the top end of its long-term range, at closer to $2Bn, given the more stringent environmental standards. The spending is supported by 2.6GW of coal retiring from 2021-2025 due to age, EPA's New Source Review and carbon rules as well as 316b water cooling rules. Some plants need a cooling water retrofit for 316b and/or scrubbers, but may be too close to retirement to justify the investment.

Increasing capex by hundreds of millions per year in longer-dated capital spending plan.

For example, DTE has announced that it will be closing Trenton Power Plant Unit 7 in 2016 for environmental compliance purposes and minimal synergies are expected as direct headcount will stay the same. This follows the earlier announcement that Unit 8 will be closed; collectively the two units have capacity of 240MW which is significant lower than the newer 535MW Unit 9. As described below, DTE plans to keep Unit 9 operational by utilizing DSI and trona to meet carbon standards.

Management's decision to retrofit Belle River with relatively cheaper DSI/ACI comes after considering the $1B cost for FGD and SCR on the 1,200 MW plant (~$800/kW retrofit appears among the most marginal we've seen thus far of late). The asset is the company's newest in the portfolio. A final decision on the more expensive systems will ultimately depend on relative coal vs gas (& marginal electric) pricing and its effect on the financial viability of the plant.

As we have highlighted recently, this continues the trend of PRB coal plants facing earlier environmental compliance spurred retirements. For further details please refer to our 6/27 report, **The Illinois Basin Opportunity** and our more recent 9/10 report **Managing Michigan's Coal Transition & the MISO Upside Story.**

DTE intends to spend $300M for the cheaper, but ultimately temporary dry sorbent and activated carbon injection controls to keep River Rouge, St. Claire, Belle River, and Trenton Channel plants operating pending the planned coal retirements through 2025 mentioned above.

DTE intends to spend $300M for the cheaper, but ultimately temporary dry sorbent and activated carbon injection controls to keep River Rouge, St. Claire, Belle River, and Trenton Channel plants operating pending the planned coal retirements through 2025 mentioned above. Michigan environmental regulators

require the utility to finish installing the systems and comply with EPA's MATS rules by April 16, 2016.

Looking for an external solution: June's Generation RFP

Self-build or acquisition? We will find out soon.

DTE issued a Request for Proposal (RFP) to potentially acquire simple or combined cycle gas plants in June as it seeks to meet its generation needs in the face of plans to retire coal plants. DTE Electric's summer procurement is 1GW which the company anticipates remaining somewhat stable in at least the near-term. Management stated that it is currently reviewing proposals and process is expected to last throughout 2014 with negotiations in October and a signed agreement available as early as December.

Figure 81: DTE Request for Proposal Timeline for Gas Power Plants

Step	Timetable
RFP Issued	June 2, 2014
Notice of Intent Due, Non-Disclosure Agreement, and Respondent Pre-Qualification Application Due	June 9, 2014
Respondents Notified of Results of Pre-Qualification Application Review	June 16, 2014
Proposal Deadline	July 11, 2014
Proposal Evaluation Completion Target	October 1, 2014
Negotiations with Selected Respondents	October 2, 2014 – December 14, 2014
Definitive Agreements Executed with Selected Respondents	December 15, 2014

Source: Company Filings

Through 2016 DTE anticipates being able to meet its projected generation MISO shortfall with PPAs and other contracts but believes that purchasing existing Michigan assets would be ideal assuming the price is right; however, emphasizing that such a move is likely beyond the current investment horizon and around 2019. The exact 'incremental' capital out of this RFP remains unclear vs. the contemplated $1.3-2.0 Bn capex range disclosed.

We flag that CMS recently confirmed that MISO capacity market pricing was indeed trending higher, with prices in the $3/kW-month range (~$100/MW-day) range despite the latest auction results for the year ahead substantially lower (~$15/MW-day), consistent with comments made by Dynegy for upwards of $2/kW-month.

A more detailed update is expected in the fall as management assesses what environmental retrofits make sense for its coal fleet as we get more clarity on the EPA's standards

P&I Growth To Continue After REF Installations

At P&I, growth is expected to come from three areas: (1) organic growth onsite at facilities, (2) renewable conversions of coal-to-wood, and (3) Reduced Emission Fuel (REF) unit installations as well as optimization and the possible movement of some units to larger plants. Management also sees the possibility of M&A, rolling up onsite power businesses, especially as low gas prices incentivizes more interest in onsite Cogen facilities. Specifically on REF, Unit 8 went into service this summer and Unit 9 is still in a test run with negotiations. As a reminder, these REF plants

are ten-year tax credit projects which expire around 2020 at which point the assets will have environmental compliance value but will experience a significant step-down.

Duke Energy (Buy; $81 PT)

Nickel beat on weather; tracking to high end of guidance for 2014

We don't expect DUK to initiate 2015 guidance until the 4Q call in Feb 2015, nor do we expect any major incremental updates on the 3Q call or at EEI.

Expect a slight beat

We expect DUK to report **$1.59** for 3Q vs consensus $1.54, with the nickel beat due mostly to mild summer weather that was a little less mild than last year (a -$0.09 impact for 3Q13) and a lower effective tax rate. Rate increases in the Carolinas help +$0.06 assuming about 28% of annual revenues flow in during 3Q. This is partially offset by -$0.02 from the absence of a benefit this year from amortization of cost of removal in Florida and another penny of D&A /AFUDC from the Sutton plant. Nuclear outage levelization is expected to decline from +$0.11 in 2013 to only +$0.05 to +$0.06 in 2014, but 1H14 was actually higher than 1H13 by +$0.03. That leaves 2H14 to be -$0.08 vs last year with most of the impact in 4Q, so we assume it's a -$0.02 impact in 3Q14. Wholesale revenues are expected to be +$0.07 to +$0.08 higher for full 2014, so we assume +$0.02 in 3Q. Weighted Average capacity prices in PJM's RTO region are significantly higher this quarter at $126/MW-day vs $28/MW-day through June. With an impact of $0.02 for each $10/MW-day, that's a +$0.05 favorable impact this year in 3Q. Renewables should be a couple of pennies higher and utility load growth should help a penny too. We expect higher Commercial Power results vs a weak 3Q13 but this will be more than offset by lower results at International, which should be hit by -$0.03 from a slide in the Brazilian Real alone (54% of the segment).

Figure 82: 3Q14 Earnings Walk

$1.46	**3Q13A Adj. EPS**
0.06	Rate Cases
	NC ($235M; Sep 2013), SC ($119M; Sep 2013)
(0.02)	COR (Cost of Removal) Amortization in Florida-> ended at yearend 2013
0.00	O&M --> Commentary to Keep it Flat from 2011-2016
0.02	Weather - was unfavorable by -0.09 in 3Q13, but also had a mild summer this year.
(0.01)	Depn/AFUDC - Sutton plant
0.00	O&M Impact from Storms
(0.02)	Nuclear Outage Levelization
0.02	Wholesale Revenues
0.05	RTO Capacity Prices Increase 6/1 to $126 from $28/MW-day
(0.05)	International - F/X / Hydrology (No Rationining Yet)
0.03	Commercial Power Generation margins for Coal
0.02	Renewables - expect $50M net income in 2014
0.01	Load Growth (~0.5%, with 100 bps = ~$0.10 eps)
0.02	Eff tax rate (32%-33% vs 34% in 3Q13)
$1.59	**3Q14E EPS UBSe**
$1.54	***Consensus***
$4.50-$4.65	***2014 Guidance***

Source: UBS estimates, Company filings, FactSet

With TTM at $4.87 vs guidance for 2014 of $4.50-$4.65, we see full year earnings tracking toward the high end of guidance, despite factors that should cause 4Q to be lower this year vs 2013, such as nuclear outage levelization benefits and the rate increases that were fully baked in to 4Q13. We don't expect DUK to initiate 2015 guidance until the 4Q call in Feb 2015, nor do we expect any major incremental updates on the 3Q call or at EEI for the various projects and initiatives discussed below.

International strategic review – don't necessarily expect a sale

We continue to suspect a partnership structure around these assets is more likely than an outright sale.

We increasingly emphasize Street expectations for a sale of the International business are likely misdirected, with a variety of other potentials clearly before management. We emphasize a direct sale of the business would appear dilutive given depressed regional multiples in the Americas (generally in the ~6x EBITDA range), and with management committed to making any transaction accretive, this would appear a tough hurdle to cross.

Focus is on driving EPS growth from the segment rather than need to divest

What's the purpose of the strategic review?

The purpose appears first and foremost is to solve the segment's relatively flat EPS profile through the forecast period. Part of the problem is the $1.7B of offshore cash there, some of which is needed to cover collateral requirements, as well as this year's reduction in ownership % of NMC. Political uncertainty around the drought isn't helping despite the improvement in power forwards in South America. We suspect management will not suffice with any outcome that does not deliver a corresponding 4-6% EPS trajectory from the business.

Could a deal with AES Tiete work? We think there's good logic.

Bringing the foreign assets back to their origin?

Among these, we emphasize the opportunity to pursue a transformative merger of the international business appears the most interesting, with synergy opportunities from bringing the business to scale. In particular, we emphasize its regional peer, AES Tiete, could yet fit nicely as a re-combining of the two asset bases (previously housed under the same parent company in a prior life). With total EPS of ~$0.23 from the Brazilian segment in 2013, we see the opportunity to add ~$0.03 from conservative synergy expectations, and most importantly enable Duke to monetize its position via a public equity listing (via a share-for-share transaction). We suspect even if AES Tiete is not the partner, Duke's bias remains to take shares with a regional partner in the Americas to gain the liquidity to gradually sell down the business.

Tax structuring remains the missing piece

Exploring ways to bring back the trapped cash

We also emphasize the key to any transaction would be resolving off-share tax considerations, enabling the company to repatriate the $1.7Bn (at least over time). We think the structure of any sale could prove crucial to effecting the appropriate tax basis.

What's the timing? Still an update by year end.

While we're not necessarily convinced a final deal will be announced by year end, we think management will delineate at least coalesce around a strategic path forward by year end.

Ohio fleet sale in final phases - expect to close around yearend

Pricing on portfolio could prove modestly better than Street expects

With the final phases of due diligence closing up, a winner is expected to be announced in the next few months with closing in late 2014 or early 2015. Management commentary has projected pricing that is likely to be ahead of the initial contemplated range in the media of $1.5-2.0 Bn. We believe pricing in the low-$2B for the portfolio, with the vast majority (~$1.5B at least) attributable to its CCGT portfolio in Ohio. We include an update of our commodity view on this portfolio below. As for use of proceeds, DUK lists the usual growth investment opportunities, avoiding future holding company financings or a stock buyback. The transaction is expected to be accretive in 2016.

Ohio Staff recommends against PPAs for remaining OVEC interest

On Oct 2, the Staff of the Public Utility Commission of Ohio (PUCO) recommended against granting a cost-based PPA for Duke's remaining 9% interest in Ohio Valley Electric Cooperative's (OVEC) 2,256-MW fleet. We view this as consistent with a similar recommendation made for AEP's ESP, which should receive a final order shortly. As we've written regarding AEP's request, we believe that regulators may choose to postpone any real decision on an OVEC PPA until after the election. As such, regulators would approve a "zero-based rider" within the ESP that allows for a PPA mechanism but without any actual rate attached to it, leaving that for a future decision, perhaps in 2015. Generally, industrial customers support such a rider to reduce volatility and electric costs, but some on the Staff are against it and make an argument that Ohio deregulation law precludes any PPAs for any reason.

Since the 2006 acquisition of Cinergy, Duke Energy Ohio, through its 9% ownership interest in OVEC, has had a long-term contract to buy power from OVEC's power plants through June 2040. In 1Q14, the carrying value of this contract had been reclassified to an asset held for sale in connection with the planned sale of Midwest Gen to Dynegy. However, in 2Q14, the OVEC interest was removed from the disposal group and on May 29, Duke Energy Ohio requested cost-based recovery in its 2014 Electric Security Plan (ESP).

Coal ash legislation passed in August, in-line with Duke's late-July proposals

The law is largely in-line with Duke's earlier proposals and requires the ash basins at Dan River, Asheville, Riverbend, and Sutton to be excavated and closed "as quickly as practicable and no later than 8/1/2019".

The Coal Ash Management Act of 2014 was passed by both NC state legislative bodies on August 20 and went into effect Sept 19th. DUK intended to move forward with remediation even in the absence of legislation. The law is largely in-line with Duke's earlier proposals and requires the ash basins at Dan River, Asheville, Riverbend, and Sutton to be excavated and closed "as quickly as practicable and no later than 8/1/2019". It further states that all active plants must convert to dry fly ash handling by 12/31/2018 (or retire the units) and dry bottom ash handling by 12/31/2019 (or retire the units). Basins are also to be categorized into High, Intermediate, and Low risk by Department of Environmental and Natural Resources (DENR) by the end of 2015, with each closed by the end of 2019, 2024, and 2029, respectively. High and Intermediate risk may not be capped in place but instead must be de-watered, excavated and relocated to lined landfills or recycled toward a beneficial use such as concrete production or roadway construction.

On cost recovery, a moratorium exists through Jan 15, 2015, although deferrals may be sought. Recovery of ash byproduct sales through the fuel clause does not apply to the moratorium. The NCUC will consider cost recovery of coal ash basin closures under the law.

Duke intends to finalize its long-term basin closure strategies by yearend 2014, with consideration of final EPA regulations on Coal Combustion Residuals that is expected in Dec 2014. Costs will be dependent on methodology for each site and the company will refine its projections as plans are finalized. The first of its three-phase review of its ash basin was completed over the Summer, with the results seeming to affirm the plan as previously proposed this Spring. We continue to expect finalization of CCR rules this December as reaffirming Duke’s proposed plan, given the latitude likely towards to states to implement their own plans (we suspect the DENR will likely submit whatever plans are finalized).

Capital or expense treatment?

How is this investment to be treated? We think the bulk of the spend will be treated as a capital investment (i.e.- eligible for ratebase treatment), rather than O&M or simply a decommissioning liability. Today, much of the recovery for future coal ash liabilities is accounted for under 'Cost of Removal' accounting as a D&A line item (at least for Progress' current ratemaking purposes).While some legislative proposals have suggested some spend could be disallowed, we believe the spend entailed in remediating ponds is largely as a result of a shift in policy towards a more stringent standard, rather than a failure to address current standards (notwithstanding the failure of the pipe at Dan River).

Our bias is to believe this will be treated as capital rather than O&M spending.

Grand jury probe into Dan River a lingering risk

While up to NC's DENR (Dept of Environmental & Natural Resources) to approve Duke's plans in '15+, the real lingering risk would be a federal grand jury investigation into the Dan River spill (although management has already indicated modest impact to clean up already, with insurance addressing the balance). Given seemingly documented concerns around the adequacy of the integrity of this pipe dating back some time, we see concerns around further costs arising from the spill. The timeline for the investigation remains unclear, but the company and other agencies have been subpoenaed. We expect this will remain among the key lingering risks to the Duke story.

What about rate recovery? No rate cases for foreseeable future

Despite the added spend from coal ash, we think timing of any further cases in the Carolinas will be predicated primarily on reflecting the forthcoming Lee CCGT, with completion in November 2017. We believe much of the spend under any gas pipeline or solar needs will likely have rate recovery mechanisms reflected in any construct approved.

Capex plan unchanged; filling in the discretionary budget

In February, DUK outlined a total $38B capital budget from 2014-2018, which included $4B of "discretionary" budget (unspecified projects). So far, $1.2B of this discretionary spend (30%) has been applied toward the purchase of the North Carolina Eastern Municipal Power Agency's (NCEMPA) minority ownership in ~700 MW of existing Duke Energy progress nuclear and scrubbed coal plants, including the Harris Nuclear Plant, Brunswick Nuclear Plant, Roxboro Steam Plant Unit 4 and the Mayo Plant. The deal includes a 30-year full-requirements load serving contract and is required to close by yearend 2016 after approvals from FERC, DoJ, NRC, and Carolina regulators.

Projects within the budget but yet to be finalized and priced out include the NC pipeline and additional commercial renewable projects.

New Generation ($6B-$8B): Total spending on new generation projects is expected to be $6B-$8B from 2014-1018, with $6.1B of projects specified thus far (including ~$2B of renewables and the $1.2B purchase from NCEMPA). Additional commercial renewable projects are possible as part of the remaining $2.8B discretionary budget. We believe renewables are also a good candidate for reinvestment of repatriated cash from the International segment as well (beyond the discretionary budget).

Beyond this disclosed capex, management stated it continues to forecast ~300 MW/yr of demand growth across its Carolinas service territory. This would suggest a need for a further CCGT every couple years (the driver to the top end of the range through the forecast period).

Infrastructure ($7B-$9B): Management has guided to $7B-$9B of spending here, with $5.5B previously identified for grid modernization, new customer additions, and commercial transmission projects. Another ~$1.9B applies to Duke's 40% stake in the $4.5B-$5B Atlantic Coast Pipeline project (see below), with approximately $900M remaining in the "discretionary budget" category.

Compliance & Other ($3B): Guidance for this group is ~$3B in total, including previously identified amounts for EPA compliance ($1.9B) and NRC Fukushima-related safety compliance ($1.3B).

Figure 83: Growth Capital Expenditures, 2014E-2018E

Growth Capital Expenditures 2014E - 2018E ($M)	
New Generation growth	
Florida CC/CT	$1,850
Other Florida	$225
Lee CCGT in SC	$600
Regulated Solar	$1,000
Commercial Renewable	$1,200
Commercial Renewable (discretionary) *	NA
NCEMPA purchase *	$1,200
Total specified projects	$6,075
Category Guidance	$6B-$8B
Infrastructure growth	
Grid Modernization/T&D/SB560	$2,375
SB560 Indiana T&D	*~$1.5B-$2.0B over 7 yrs*
New Customer Connections	$2,400
Commercial Transmission	$700
Atlantic Coast Pipeline (40% stake) *	$1,900
Total specified projects	$7,375
Category Guidance	$7B-$9B
Compliance growth	
EPA regs	$1,900
NRC Fukushima regs	$1,300
Total specified projects	$3,200
Category Guidance	~$3B
Other growth	
Major Nuclear Upgrades	$1,300
Other	$1,100
Total specified projects	$2,400
Total specified growth projects	$19,050
Remaining Discretionary Growth Budget *	$900
Growth investment guidance 2014-2018	$16B-$20B
* Draws from $4B "Discretionary Growth" budget	

Source: Company filings, UBS Estimates

Figure 84: Non-Growth Capital Expenditures, 2014E-2018E

Non-Growth Capital Expenditures 2014E - 2018E ($M)	
Non-growth CAPEX	
Nuclear Fuel	$2,700
Regulated Maintenance	$14,975
Midwest Gen	$125
International	$300
Total specified projects	$18,100
Total Growth & Non-Growth	$38,050
Total 2014-2018 CAPEX Guidance	$34B-$38B
Environmental 2014-2023	
Air (25%), Water (25%), Waste (50%)	$4.5B-$5.5B
Baseline NC ash basin	$500
Ultimate ash cost range	$1.0B-$10.0B

Source: Company filings, UBS Estimates

Resolution around coal is constructive – and upside to capex budget

We reiterate our view on shares reaching an 'inflection' point

Separate from the growth categories above, the company has also projected $4.5B-$5.5B of environmental spending over the next 10 years through 2023. This is separated into three buckets; 25% air pollution controls, 25% water, and 50% waste management, including coal ash ponds and conversion. DUK has already earmarked a $500M placeholder for baseline NC coal ash remediation, including excavation of coal ash at Dan River, Riverbend and Sutton to a new, lined landfill

or structural fill solution. There may be potential for this bill to inflate from $1.0B-$1.5B for a "hybrid cap in place" at 10 remaining sites to $7B-$10B for an "all-dry systems" solution. DUK's baseline assumption is a $2.0B-$2.5B plan that includes dry bottom ash handling & fly ash reliability improvements as well as moving three sites to new, lined structural fills or landfills while continuing the Asheville structural fill and converting remaining units to dry fly ash.

Duke gets environmental uncertainty and clarity

Ohio River spill takes some of the optimism away from the NC Coal Ash bill.

Adding to its environmental woes, In August, DUK reported a spill of ~3,000-5,000 gallons of fuel oil into the Ohio River at its W.C. Beckjord Station, southeast of Cincinnati. A 15 mile stretch of the Ohio River was closed down as a result of the spill. Ironically, this almost coincided with the approval of a bill in North Carolina (NC) designed to regulate coal-ash dumps – the origins of that bill lay in a coal ash spill at a Duke Energy power plant on Dan River six months ago, which led to environmental concerns and regulatory debate over coal ash pits across the state. The NC bill, however, is being viewed as a compromise – for it asks for DUK to remove ash at four "high risk" ash pits, while a Commission will be created to decide on what should be done with the remainder of its "low risk" coal fired fleet (one of the options being discussed for those lower risk pits is to simply cap them with plastic sheets and dirt). DUK will get a chance later in January to pitch to regulators its case for passing on clean-up costs to customer.

Duke opts to accelerate retirement of Beckjord units

The coal unit's fate appeared sealed when it was not included in the Dynegy transaction.

Duke announced at the end of August that it would retire Beckjord Units 5 and 6 (~400MW Duke ownership) effective September 1st, the same plant that had a diesel fuel spill earlier in August. These last two units will join Units 1-4 in retirement and effectively end Duke's Midwest merchant operations following the August 22nd announced sale to Dynegy (please refer to our note **'Marrying Up the Power Business'** for details of the transaction for both Dynegy and Duke). Management stated that the fuel spill was not a direct cause of the accelerated retirement of the units but offered a convenient opportunity to wind-down operations. While Duke owns 100% of Unit 5, Unit 6 is jointly owned with AEP (12.5%) and AES' Dayton Power and Light (50%).

Next on deck? Could follow suit on ratebasing gas reserves in Florida

While management is observing the outcome of NEE's small gas ratebase pilot program, this potentially important opportunity is not yet being actively considered by the company.

Duke still evaluating possible purchase of 600-MW Osprey CCGT from Calpine

Still waiting on a deal

While a deal has yet to be formally inked, regulatory filings suggest Calpine has lowered its offer price for the plant following recent media scrutiny of DUK's plan to build new peakers instead of contracting for the relatively new (2004), existing plant. (Docket 140111). In May 2014, the plant's current PPA expired and we estimate a new PPA (likely ~2015 effect) would be in the ~$3/kW-month range, backing into a limited (~$10 Mn/yr) EBITDA contribution. In turn, we suspect an eventual asset sale at PPA termination of ~$200-300/kW (~$120-180 Mn), a discount vs. the implied $449/kW for the latest southeast portfolio, and while we see upside to our initial estimate, we see an implied EV/EBITDA into the teens.

New solar projects announced

We see utilities as recognizing the benefits of having a real presence in solar – and see the low barriers to entry as illustrative in the recent series of deals to both acquire existing assets as well as develop new sites. Without the need for expensive tax equity (rather used directly to offset taxable income), we see merits to continued expansion. We flag anecdotally returns on utility-scale deals have seen significant compression in recent years, from mid-teens returns on the first wave in 2009 to mid-to-high single digits on latest deals according to some (6-8%). The three major southeast utilities, DUK, D, and SO (in addition to NEE's significant existing market position) all appear poised to continue to build out these businesses – ahead of a potential 'greening' of the Southeast market in coming years/months.

DUK acquires 3 solar projects adding to 128MW; signed PPAs for another 150MWs spread over 5 projects

Duke announced plans to acquire and build three solar projects totalling 128MW in Bladen, Duplin and Wilson counties, North Carolina. They also signed PPAs for five other new solar projects totalling 150MW in the state. The company has allocated $500mn for all eight of these projects. Duke currently has a 300MW RFP in North Carolina and is able to invest in up to 150MW of projects in South Carolina by 2021 through the current legislation.

More wind in Texas too?

Ramping up wind side too

Earlier this month Duke had also announced its plans to build and operate a 110MW wind farm in Texas at the Los Vientos wind farm. The new capacity will be sold under a 25-year PPA to Garland Power & Light and other local municipalities. Upon expected completion in 2H15, Duke will have 912MW of capacity at its Los Vientos I-V projects in Texas and over a 2.1GW wind portfolio.

We continue to expect DUK's management to continue to push forward on ~2bn renewables investments at its utilities in both NC and SC in the 2014-18 period – split between Commercial Renewables (previously disclosed to be $1.2bn of the investment) and regulated solar (we estimate at $1bn based on previous disclosures).

Plans to spend $2.6bn on transmission line

Part of a broader $8bn project planned amongst 4 companies.

Duke, in conjunction with Pathfinder Renewable Wind Energy, Magnum Energy and Dresser-Rand, announced a green energy initiative in September which would include building a ~2MW wind farm in Wyoming, a ~1.2MW underground storage facility in Utah, and a 525-mile electric transmission line connecting the two sites – which would cost ~$8bn, and be operational by around 2023. The wind farm will be owned and built by Pathfinder, and cost about $4bn. The storage facility will be built by Pathfinder Renewable Wind Energy, Magnum Energy and Dresser-Rand, for around $1.5bn, and will be a compressed air system with a maximum potential to store the energy equivalent of 60,000MWh of electricity, according to the company's press release. Duke will handle the third project, which is $2.6-billion, 525-mile, high-voltage transmission line connecting the Wyoming wind farm to the Utah storage facility. An existing 490-mile transmission line will be used to transport power from the storage facility to the intended load center in Los Angeles. We emphasize the project will likely face significant development hurdles given numerous permitting issues in California- and elsewhere. That said, we appreciate management's pro-active approach to pursuing growth opportunities. We think more regional partners would be needed to really have success on this project.

Some more uncertainty at Edwardsport

Duke could face recoverability issues around Edwardsport financing costs related to project delays.

In September, the Indiana Court of Appeals ruled that the Indiana Utility Regulatory Commission (IURC) must reconsider its rate-increase decision of April 2013 which had authorized Duke Energy to recover $61 million of financing costs it had incurred due to construction delays on the 618-MW Edwardsport IGCC plant. The rate increase had been authorized as part of the rider that allows costs related to the IGCC plant to be reflected in Duke's rate base outside of a base rate case. Previously we had highlighted the risks associated with underperformance from Edwardsport this winter; however, it appears that the unit has run with far fewer issues lately and is meeting management's expectations.

This ruling does not say that the IURC must reverse its rate-increase decision, but only that it should review and reconsider it. Nonetheless, it does throw in an element of further uncertainty and raises the perception of recovery related risk. The ruling may also translate into a deeper scrutiny during review of Duke's IGCC 12 and 13 rider dockets (which are combined to a single docket with) for which hearings are set for November 3 with a final order expected in 1H15.

Conversion of post-in-service O&M to capitalized cost may trigger additional writedowns

The IURC had earlier shifted its review of the plant's in-service declaration and subsequent use of power (to power the gasifier) when output was zero ("net negative generation") into the combined IGCC 12/13 docket, rather than review this as a sub-docket of the fuel adjustment clause FAC-99. Previously we earlier highlighted that an important consequence of such a move had been that the review of net negative generation would include the costlier winter months within a full-year timeframe. Rather than risks around capital cost recovery, the focus has rather been on recovery of O&M and purchased power since the June 2013 in-service declaration. One argument being advanced by challengers is that purchased power for the plant appears much larger than the usual "negative generation" seen in other much smaller plants, such as spinning reserves. The larger scale of costs is then cited as evidence that the plant should never have been declared in-service in June 2013, and thus some portion of the O&M and purchased power that has been in rates since IGCC 10 (Sept 2013) should have been capitalized rather than deferred for cash recovery as O&M.

The plant's total expected cost is currently $3.55B, for which the company has already written down $900M, with max recovery capped through the IGCC riders to $2.65B. While the current level of capital spending has yet to exceed the company's $3.55B budget (it's very close though). Along with an additional risk of the IURC possibly reversing its April 2013 decision after the Indiana Court of Appeals ruling last week to review (the IURC does indeed also have the option to not change its rate increase decision after review), we note that any conversion of post-in-service O&M to capitalized cost as a result of the IGCC12/13 review in November could trigger additional writedowns.

Estimates and Valuation; Maintaining PT of $81 on higher estimates and multiple expansion; Reiterate Buy rating

Our estimates sit at the top end of 2014 guidance and we previously raised our 2015-2018 estimates a bit to reflect a higher weather-adjusted load growth rate going forward vs management's conservative 1.0% long-term guidance. Our price target of $81 is based off a straight 10% premium to the 2016E average regulated utility multiple.

Figure 85: Revised UBS Estimates, 2013A-2018E

DUK EPS	2013A	2014E	2015E	2016E	2017E	2018E
UBSe	$4.35	$4.64	$4.81	$5.05	$5.25	$5.47
Prior UBSe	$4.35	$4.64	$4.81	$5.05	$5.25	$5.47
Consensus	$4.35	$4.61	$4.77	$4.98	$5.26	$5.60
Guidance	$4.50-$4.65					
	Grow EPS 4%-6% through 2016 off 2013 guidance $4.33					

Source: UBS estimates, FactSet, and Company Filings;

Figure 86: DUK P/E Valuation, 2016E

Price Target Valuation		
EPS	$5.05	2016E
x	14.5x	Group Avg Multiple
x	10%	Premium
PT	**$80.52**	

Source: UBS Estimates

Dynegy, Inc. (Buy; $43 PT)

With the ECP/DUK public financing secured, will shares be able to shake underperformance? FY14/15 guidance increases are telegraphed but call could be lacking in catalysts.

Dynegy is estimated to report 3Q14 adjusted EBITDA of **$140Mn**, up ~$30Mn YoY and higher than consensus by the same amount with the Street seemingly forecasting greater erosion in the legacy business. The projected improvement in coal is essentially offset by lower contributions from GasCo which continues to be impacted by the California contract expiration. Higher delivered coal costs (~$14-15Mn) will continue to be a negative but we estimate that higher realized prices (not as much of an uplift as was in 2Q) will continue to prevail. Despite no contribution last quarter due to poor capacity factors, the contribution from the IPH fleet is forecasted to comprise the entirety of the YoY improvement.

With CoalCo and Gas essentially offsetting, YoY improvement driven by contribution from IPH; Consensus predicts a flat quarter.

Increasing 2015 guidance likely to offset any 3Q specific weakness

While not the big focus for investors of late with the DUK/ECP transaction stealing the limelight, we see latitude for management to increase its standalone FY14 adjusted EBITDA guidance to **$350-400Mn** from $330-380Mn. As we elaborate on below, following the improvement in Power recently we now estimate pro-forma adjusted EBITDA of ~$1.4BMn, presenting sufficient latitude for management to increase 2015E guidance by $200Mn to **$1.4-$1.6Bn** from $1.2-$1.4Bn communicated with the DUK/ECP deal announcement.

Guidance: Improvement in power prices could lead to $20Mn FY14 (legacy) increase while the pro-forma fleet could see a tenfold improvement ($200Mn).

Figure 87: 3Q14 Earnings Walk

$ Mn	3Q14E	3Q13A	Notes
Consensus EBITDA	*$110*		
Adj. EBITDA UBSe	140	113	
Corp & Other	(17)	(14)	*Higher G&A YoY offset by PRIDE*
IPH	24	-	*Deal closed on Dec 2nd, 2013 (Guidance @ $75 Mn Run-Rate before G&A)*
CoalCo	26	6	*Higher Coal Contracts (-$15 Mn), offset by better pricing (Congestion has been very limited in '14)*
GasCo	107	121	*Capacity & RA pricing +$23Mn, along with Independence / Ontelaunee better given Basis + Casco Fuel Supply (+ve)*

Source: Company Filings, FactSet, UBS Estimates

Links to our relevant recent research are below:
9/24/14 Driving the Story Home
9/12/14 Managing Michigan's Coal Transition & the MISO Upside Story
9/8/14 Super-Sizing the Portfolio
8/26/14 What does the Dynegy Deal Mean for the Sector?
8/22/14 Marrying up the Power Business

Powering Higher: Potential 2015 Guidance Revision

Below we present our latest standalone and pro-forma adjusted EBITDA estimates for Dynegy which are materially higher since mid-August, and even since early September MoM. **We now estimate 2015E adjusted EBITDA of $1.5Bn and believe management could increase its guidance ~$100-$200Mn to $1.4-$1.6Bn, off the $1.2-1.4Bn announced with the transaction.** Given the trade off in the last couple days (and the underlying volatility), we sense management

could opt to raise 2015 only modestly – holding off ahead of a further potential revisions with additional synergies in early 2015 post the close of the deal.

What's the most under-stated element of Dynegy pro-forma for deal?

We think many investors have largely understated the extent to which Dynegy is now a 'gas' portfolio rather than a 'coal' portfolio, split roughly 1/3rds vs 2/3rds. We estimate the Dynegy Classic coal portfolio generates ~$100 Mn/yr in EBITDA, IPH just under this, the ECP Kindcaid plan in IL ~$80 Mn/yr, and lastly the DUK Midwest portfolio ~$100 Mn as well (~$400 Mn/yr in total out of ~$1.3-1.5Bn run rate portfolio).

Figure 88: Stand-Alone and Pro-forma Adjusted EBITDA Estimates

Pro-Forma Dynegy-Ameren Estimates	2012A	2013A	2014E	2015E	2016E	2017E	2018E
Midwest (Dynegy Inc.)	12	50	155	221	202	189	187
West	111	95	49	48	54	11	11
Northeast	1	137	187	169	135	133	161
Illinois Power Holdings (Standalone)		12	81	83	88	108	123
PRIDE Reloaded (Mostly Gross Margin/Not O&M)				48	85	85	85
Consolidated G&A	(90)	(76)	(100)	(100)	(100)	(100)	(100)
Pro-Forma DYN-DUK-ECP Open EBITDA Estimates							
Duke Energy Ohio		143	202	424	308	309	372
Duke Operational Synergies				22	48	48	48
Energy Capital Partners		-	383	570	456	495	458
ECP Operational Synergies		-	-	8	12	12	12
Balance Sheet Efficiencies		-	-	20	20	20	20
Options Drag (4Q11-2012)	(157)						
Adj. Pro-Forma Combined Deal EBITDA	(123)	362	957	1,513	1,308	1,310	1,378
Guidance				1200-1400 --> 1400-1600?			
Adj. EBITDA (Standalone DYN + IPH)		219	372	468	464	426	468

Source: Company Filings, ThomsonReuters, and UBS Estimates

Moving Past The Capital Markets

Dynegy completed a busy week of financing which we summarize below:

Dynegy finishing tapping the equity and debt markets for $6.2Bn.

- **Equity: $1,064Mn**
  - 22.5Mn Shares of Common Stock at $31/Sh
  - 4Mn Shares of Mandatory Convertible Preferred Stock which will convert automatically on November 1, 2017 into 2.5806-3.2258 shares depending on pricing and volume. The P/S will pay a 5.375% dividend if declared by the Board.
- **Debt: $5,100Mn**
  - $2.1BN due 2019 at 6.75%
  - $1.75Bn due 2022 at 7.375%
  - $1.25Bn due 2024 at 7.625%

Underwriters have the option to 3.375Mn shares of common and 600K shares of preferred (collectively up to 5.3Mn of additional shares); however, given Dynegy's strong free cash flow generation, we see them as in a position to repurchase shares as soon as 2016 so currently exclude the additional potential dilution and use of proceeds from our calculations. In the absence of an offsetting use of proceeds, the full underwriter's option would reduce our valuation by $1.50/sh. The interest rate on the debt compares with a $500Mn 2023 Dynegy Inc. note at 5.875% and $250Mn 2020 GenCo note at 6.3%.

Absent use of proceeds on the $165Mn of potential greenshoe offering, additional dilution would reduce our valuation by $1.50/sh.

Further notes on projected share count:

- Final issuance for ECP $200 mn equity stake will be predicated on 10-day average trading price prior to close (late December), worth ~6 Mn shares
- Management stock compensation is 1-1.5 Mn shares/year. The key question heading into 2015 – given its FCF will be whether management opts to continue issuing the shares rather than immediately offsetting the issuance.

Figure 89: Dynegy Debt Profile at 12/31/13

Dynegy Debt Carrying vs Fair Value	As of 12/31/13		As of 12/31/12		Change	
	Carrying Value	Fair Value	Carrying Value	Fair Value	Carrying Value	Fair Value
Dynegy Inc.						
Tranche B-2 Term Loan (Due 2020)	(792)	(802)	-	-	(792)	(802)
5.875% Senior Notes (Due 2023)	(500)	(468)	-	-	(500)	(468)
Emission Repurchase Agreements	(17)	(17)	-	-	(17)	(17)
Interest Rate Derivatives	(47)	(47)	(46)	(46)	(1)	(1)
Commodity-Based Derivatives	(19)	(19)	(12)	(12)	(7)	(7)
C/S Warrants	(21)	(21)	(20)	(20)	(1)	(1)
Dynegy Subtotal	(1,396)	(1,374)	(78)	(78)	(1,318)	(1,296)
DPC Credit Agreement	-	-	(880)	(874)	880	874
DMG Credit Agreement	-	-	(535)	(537)	535	537
AER GenCo:*						
7.95% Senior Notes Series F (Due 2032)	(224)	(216)	-	-	(224)	(216)
7.0% Senior Notes Series H (Due 2018)	(259)	(252)	-	-	(259)	(252)
6.3% Senior Notes Series I (Due 2020)	(200)	(196)	-	-	(200)	(196)
AER Subtotal	(683)	(664)	-	-	(683)	(664)
Grant Total	(2,079)	(2,038)	(1,493)	(1,489)	(586)	(549)

*Carrying value Includes $142Mn of unamortized discount

Source: Company Filings

Adjusted Debt / EBITDA a Bit High but FCF Offers Support

When normalizing for Brayton Point and the West assets we arrive at ~$450Mn of adjusted FCF in 2016 and $1.4Bn of adjusted EBITDA. When we met with management at the end of September they stated that the focus is to maintain a net debt / EBITDA of ~4.5x (gross ratio of ~5x) and values the associated financial flexibility with an ultimate aim of having the transaction be credit neutral or positive (targeting a 'BB-type rating' for the company).

Figure 90: Pro-Forma Dynegy "Int. Expense"

Pro-Forma Dynegy "Interest Expense"	
Prior Interest Expense	($132)
New Interest Expense	($372)
Mandatory Convert Divs.	($25)
Total "Interest" Expense	**($529)**
Cash Int. Exp. Guidance	**($480)**

Source: Company Filings and UBS Estimates

Figure 91: Updated Pro-Forma Dynegy Metrics

Segment Level FCF	2014E	2015E	2016E	2017E	2018E
DYN/IPH					
Dynegy Inc	334	404	376	318	346
IPH	38	64	87	108	123
Total	372	468	464	426	468
Capex					
Dynegy Inc	(110)	(114)	(133)	(137)	(149)
IPH	(48)	(55)	(64)	(79)	(195)
Total	(158)	(169)	(197)	(216)	(343)
Guidance	(160)				
Interest Expense					
Dynegy Inc	(73)	(73)	(73)	(73)	(73)
IPH	(59)	(59)	(59)	(59)	(59)
Total	(132)	(132)	(132)	(132)	(132)
Guidance	(145)				
FCF by Segment					
Dynegy Inc	151	218	170	108	124
IPH	(68)	(50)	(36)	(30)	(131)
FCF from legacy DYN/IPH (A)	83	167	135	78	(7)
DUK/ECP					
Additional EBITDA (ECP/DUK)		1,044	844	884	910
Additional Debt					
2019 Notes		2,100	2,100	2,100	2,100
2022 Notes		1,750	1,750	1,750	1,750
2024 Notes		1,250	1,250	1,250	1,250
2019 Notes		6.75%	6.75%	6.75%	6.75%
2022 Notes		7.38%	7.38%	7.38%	7.38%
2024 Notes		7.63%	7.63%	7.63%	7.63%
Interest Expense on New Notes		(366)	(366)	(366)	(366)
Elwood Bonds		(6)	(6)	(6)	(6)
Mandatory Convertible		460	460	460	
Interest Expense @ (5.375%)		(25)	(25)	(25)	
Maintenance Capex		(110)	(110)	(110)	(110)
Environmental Capex		(20)	(20)	(20)	(20)
FCF from DUK/ECP (B)		518	318	358	408
Grand Total FCF (A+B)		685	452	436	401
Net Debt Balance (incl. Mandatory thru	6,704	6,019	5,567	5,131	4,270
Pro-Forma Net Debt/EBITDA		3.98	4.26	3.92	3.10
FCF Yield		17.2%	11.4%	11.0%	10.1%
Stock Price		27.46			
Shares Outstanding (incl. Mandatory Dilution)		145			
Market Cap		3,978			
Pro Forma EV/EBITDA		6.6x	7.3x	7.0x	6.0x

Source: Company Filings and UBS Estimates

Metrics include the contribution from the West assets and Brayton Point.

On our 2016E we see a 4.25x adjusted net debt / EBITDA, in-line with management's target. For comparison, net debt / EBITDA was ~2.9x in 2013. The FCF yield of 11% counters the high debt ratio to some degree and we expect capital allocation to come into focus as we move deeper into 2015 as the portfolio generates significant cash flow. Absent the mandatory convertible dividend, total

interest expense following the deal is ~$505Mn, $25Mn above management's guidance which was likely based on the midpoint of the $4.9-$5.1Bn debt financing range.

But what could AEP compensation mean for DYN and AES?

If all of Duke (Dynegy)'s co-owned assets were contracted, this would represent 1.8GWs. Assuming the same contract rate, this would be ~**$135 Mn** in additional EBITDA (~10% improvement)

Valuation: Latest MTM Drives PT Into $40s

Our sum-of-the-parts valuation for Dynegy is below where we apply a 9x EV / EBITDA multiple on the run-rate 2016 adjusted EBITDA (adjusting for Dynegy's West peaking assets and ECP's Brayton Point which is slated to retire in Spring 2017). We give credit for the incremental cash flow generation through 2016 and the NPV of the NOL tax shield. Since our last mark-to-market in early September we estimate that 2016E adjusted EBITDA has increased by $135Mn on improving power prices. Following the capital market financing this past week we have incorporated the actual capital structure into our valuation and with management opting for the high-end of the debt range ($5.1Bn) and above the midpoint of the equity range ($1.064 including converts), higher dilution/lower FCF shaves a dollar off our valuation. For conservatism we assume that the mandatory converts will translate into common at 3.2258 (high-end)

Increasing PT $7 to $43 on MTM which is up $135Mn since early September and in the ballpark of $200Mn since the deal was announced.

Valuation improved by $1.2Bn ($135 at 9x) but offset by ~$150Mn of financing drag.

Our valuation continues to include $20Mn of operational synergies above the $40Mn of operational synergies disclosed as well as $200Mn of balance sheet efficiencies ($20Mn at a ~10% cost of capital) to reflect our expectation of management's ability to further unlock value. While unlocking synergies to the magnitude of the Ameren transaction appears unlikely, we do not believe the ~$5-10/kW is an unrealistic expectation for the fleet.

Every $10Mn of incremental synergies is worth approximately $0.60/sh of incremental value.

Figure 92: Updated Dynegy Sum-of-the-Parts Valuation

DYN Accretion Calcs. ($Mn)	Duke Merchant	EquiPower	Dynegy	Combined	Guidance
2016 Adjusted EBITDA	$356	$468	$464	$1,288	
Plus: Run-Rate Synergy Uplift	$16	$4	$20	$40	
Less: West Peaking and Brayton Point	$0	-$97	-$45	-$143	
Run-Rate 2016 EBITDA Estimate	$373	$374	$438	$1,185	
	31%	*32%*	*37%*		
		Consolidated			
EV / EBITDA	8x	9x	10x		
Enterprise Value	$9,483	$10,668	$11,854		Represents $200Mn of B/S efficiencies at 10% ($20Mn) +$20Mn incremental
Less: Pro-Forma Net Debt	(6,210)	(6,210)	(6,210)		
Plus: FCF 2015 & 2016	1,238	1,238	1,238		
Plus: NPV of NOL Shield for Taxes	480	480	480		
Plus: 2017 Brayton FCF	80	80	80		
Plus: EBITDA of West Peaking + Brayton	143	143	143		
Equity Value	$5,134	$6,319	$7,505		
Equity Issuance	$1,250	$1,250	$1,250		
Shares Outstanding (Assuming Convert @ 3.2)	146	146	146		
Valuation	**$35.08**	**$43.18**	**$51.28**		
Every $10Mn of incremental synergies ≈ $0.60/sh incremental value					
Prior EBITDA (Early September MTM)	$338	$400	$414	**$1,152**	
Net Increase Since Previous Note	$18	$68	$50	**$136**	

Source: Company Filings and UBS Estimates

PRIDE Take II in March?

Following our discussion with Dynegy we believe that our $20Mn of synergy assumption over the initial guidance could yet be conservative

Management provided additional clarity on the $40Mn of synergies announced with the Duke/ECP deal as well as the potential for additional savings in the future. Out of the $40Mn of synergies announced, ~$9Mn relates to coal commodity and transportation savings with the majority pertaining to Kincaid (1.1GW PJM). The balance of the savings is from duplicate overhead at ECP (~$10Mn) and Duke (~$20Mn). The key here is that management's initial synergy number does not include plant level operational savings from running the specific assets more efficiently. While there could be some dis-synergies on the ECP side (we understand that the private equity firm had less staff than Dynegy would have for a comparable asset), overall there should be additional savings due to Duke 'over-staffing' the plants relative to Dynegy. The company stressed that efficiencies would be derived primarily from PRIDE-like initiatives where the Dynegy is able to run plants leaner than many peers and will derive benefits that way. To the extent that Dynegy is able to be a successful operator of its jointly owned assets the potential also exists for Dynegy to charge the co-owners a port. Additionally, Dynegy noted that there are some programs that Duke employs that could be used on Dynegy's legacy fleet which could help the company extract further savings from its legacy assets.

The first update on synergies is unlikely to be provided until Dynegy has operated the assets for 'a few months' which puts the timeline around the 4Q14 earnings call.

Edison International (Buy; $60 PT)

$0.10 beat on consensus that's skewed by a wrong consensus estimate

Expect a SONGS settlement PD to be released in time to be approved at the Nov 20th vote.

SCE's GRC needs a new presiding commissioner with Chairman Peevey leaving.

We expect EIX to report a dime beat vs $1.28 consensus that includes a stale $0.92 estimate ($1.34 excluding it). Our **$1.38** (diluted) is slightly below last year's $1.42. In the table below we've opted to build a bottoms-up distribution of quarterly earnings for 2014 rather than the usual incremental year-over-year analysis, which we think would be less useful considering the large skewing effects of the removal of SONGS ratebase and the outcome of the soon-to-be approved modified settlement agreement (see below), with EIX and SRE both wholly accepting the CPUC's requested modifications. We've expect ratebase earnings to be distributed in about the same pattern as quarterly earnings were distributed prior to the SONGS shutdown. The removal of SONGS ratebase costs -$0.07 but this will be partially offset by +$0.04 of annualized earnings on the associated regulatory asset ($0.03 for 2014). Income tax benefits from the repair deduction are expected to be +$0.14, for which we've assumed will be distributed roughly along with earnings, although the actual pattern is subject to management discretion. Another $0.23 of 1x tax benefits flowed in to 2Q, with some more possible in 2H. Cost savings of +$0.35 are mostly from reduced labor costs (non-SONGS) and other reductions that were developed over time throughout 2013 and into this year. Energy efficiency incentives of +$0.03 are expected only in 4Q and parent expense typically runs a bit over a penny a month, but we've assumed slightly less than company guidance for this year based on 1Q results.

Figure 93: UBSe 2014 Quarterly Earnings Distribution

		Pre-SONGS Shutdown EPS Distribution			
Year	Q1	Q2	Q3	Q4	Total
2009	24%	24%	34%	18%	
2010	24%	18%	42%	17%	
Average	24%	21%	38%	17%	
		UBSe 2014 Estimate Distribution			
Ratebase	0.81	0.77	1.28	0.52	3.40
SONGS shutdown	(0.02)	(0.02)	(0.02)	(0.02)	(0.07)
Reg Asset earnings	-	0.01	0.01	0.01	0.03
Income tax benefit	0.03	0.03	0.05	0.02	0.14
Cost savings	0.10	0.08	0.08	0.08	0.35
Energy efficiency	-	-	-	0.03	0.03
1x Tax benefits, FERC sett, other		0.23	0.01		0.24
Parent & other	(0.03)	(0.03)	(0.03)	(0.03)	(0.11)
UBSe 2014 (basic)	0.90	1.08	1.39	0.63	4.01
UBSe 2014 (diluted)	0.89	1.07	1.38	0.62	3.97
Consensus			*1.28*	*0.68*	*3.90*
Core EPS Guidance (expect to be raised 0.03 for SONGS reg asset)					*3.60-3.80*

Source: Company filings, UBS estimates

Guidance coming up for 1x tax benefits

On the 2Q call, management expected to be well above the high end of the $3.60-$3.80 range for 2014 after reporting $1.98 for 1H (basic). Guidance will be now be updated and will presumably include the $0.23 of 1x YTD "core" tax reserve reversals, repair and cost of removal deductions, generator refunds, and additional FERC revenue, as well as any additional similar items for 2H14. Once the SONGS settlement is approved on Nov 20, we also expect guidance to include an incremental $0.03 of regulatory asset income too ($0.04 ongoing). Furthermore, we do not expect any material updates on either the MHI suit, in which both parties are currently picking arbitrators, or NEIL insurance coverage, with a possible coverage determination after NEIL quarterly board meetings.

CPUC orders relatively minor modifications to EIX/SRE SONGS settlement

With all modifications accepted, we expect a PD soon, in time to achieve final approval on Nov 20 after a 30-day review period.

On 9/5, Commissioner Florio and ALJs Darling and Dudney issued an order to the settling parties in the SONGS to consider several modifications to the settlement that was reached on 3/27 in order to satisfy "the public interest". All modifications were accepted. In our opinion, the suggested modifications have a relatively minor impact on EIX/SRE and in any case have virtually no material effect on SCE's $730M write-off of SONGS nor will it reduce the full recovery of the remaining $1.344B SONGS regulatory asset, $1.4B replacement power & fuel, and ~$1B of O&M recoveries. The settlement removes what had been a major overhang over the equity for years. While Commissioner Florio has been involved in PCG's recent ex-parte email revelations, we do not believe the resulting investigations and turmoil will delay approval of the SONGS settlement.

For details on the settlement, see our 3/28 note "Hitting the High Notes with SONGS". The CPUC's proposed modifications included: (1) a change in the formula for MHI lawsuit recovery sharing with customers to a 50%/50% split with shareholders instead of the current agreement to start at 15% to customers for the first $100M, scaling up to 33% for the next $800M and for amounts beyond that, 75% to customers. The new 50% split would benefit customers more for small payouts below $900M, but would benefit shareholders in the event of a large recovery. The CPUC also increased the customer allocation of NEIL insurance recoveries from the current 82.5% up to 95% under the theory that since replacement power is being paid for by customers, more of the outage insurance should accrue to them.

SCE has requested arbitration through the International Chamber of Commerce seeking $4B of damages and its position is that the $138M warranty cap does not apply in this case because the steam generator tube leak and resulting damages represent a total and fundamental failure of performance by MHI ("failure of essential purpose" and "gross negligence"). In December 2013, MHI responded with $41M of counterclaims against SCE, for which the utility has denied any liability. Regarding NEIL insurance, there is a $2.75B accident liability limit plus $3.5M per unit per week for outage costs after a 12 week deductible and subject to a limit of $392M-$490M depending on interpretation. According to the company, SCE's share of estimated claims under the accidental outage insurance through Dec 31, 2013 is ~$320M. However, accidental outage policy benefits are reduced by 90% for the periods following announcement of the permanent retirement of SONGS and the company has not yet submitted a proof of loss under the accidental property damage insurance.

Another modification has the company share 50% of all savings with customers from any possible refinancing of the SONGS regulatory asset at rates below the settled recovery weighted average return of 2.95% in 2012, 2.62% for the period 2013-14 and a rate that will float after that with changes in SCE's authorized cost of debt and preferred. In our opinion, this provision is unlikely to be triggered, but in any event is immaterial (even a 1% reduction in cost of capital would have been only $0.03 EPS, which would now have to be shared, representing a penny or two reduction in potential upside at most).

The CPUC's modifications also require that EIX agree to fund new technologies to reduce carbon emissions at no more than $5M/year.

General Rate Case (GRC) needs a new commissioner

With Chairman Peevey announcing his decision to not seek another term at the end of this year, a new presiding commissioner is now needed for SCE's GRC. The recent revelations of inappropriate ex-parte communications between sister company PCG and Commissioners Peevey and Florio do not directly affect EIX. However, EIX was mentioned obliquely in some of PCG's recent ex-parte email disclosures as having been asked to contribute funds to several Peevey causes. The company says they refused to comply with Peevey's request for funding opposition to the AB 32 climate change law and only contributed $20k to the CPUC's "event fund" (vs the $100k ask).

Separately, Senator Boxer (D-CA) recently announced that she will hold hearings to address the alleged failure of the NRC to require a license amendment for San Onofre's steam generator replacement after a 2009 inspection. This follows an Oct 2nd NRC report from its Inspector General that concludes that the NRC "missed an opportunity". The implication is that a more thorough inspection would have required the amendment and stopped the failed and costly replacement from occurring in the first place. Both SCE and the NRC state they are studying the report.

Once approved, the settlement effectively clears management's regulatory calendar to focus squarely on its GRC, which EIX hopes to finish by early-mid 2015 (retroactive treatment to Jan 1, 2015 has been approved). As we wrote in our 2/27 note "Upbeat 2014, But the Reset is Coming", a successful GRC outcome (which we now think is likely) opens the path to a 7%-9% ratebase CAGR, among the strongest of utilities we track. As noted below, upside can still come from energy storage projects, the Orange County preferred resource pilot, and CAISO transmission projects.

Large Capital Investment Needed for Distributed Gen Integration

On the 2Q call, management described as "by far the largest additional future investment in the grid" not yet in plan as a set of distribution system upgrades to support two-way flow from distributed generation. EIX intends to submit a distribution resource plan (similar in scope to the plan recently produced by Hawaiian Electric Industries) to the CPUC in 3Q15 in compliance with AB 327, which implements residential rate re-design and tier collapse along with fixed charges. A decision on these issues is due from the CPUC in Spring 2015 and a separate docket was just established on July 10 to overhaul the net metering tariff as well (decision on that expected in Fall 2015).

Beyond-2017 capital is on the come, with a regulatory filing in Fall 2015

This will summarize the incremental investment opportunity (outside of even its future GRC).

California's answer to 'Utility 2.0' is AB327.

Long-Term Procurement Plan (LTPP) final selection on Oct 16

LTPP Track 1 Local Capacity Requirements (LCR) includes 1,400-1,800 MW of preferred resources (demand response, renewables), gas-fired generators, and energy storage to replace once-through cooling units. Track 4 also authorizes 500-700 MW to be online by 2022 to replace SONGS. Final selection is expected on Oct 16. The utility has also submitted its own stalking horse self-generation bids as well.

Expect details Thursday.

Figure 94: SoCalEd Long-Term Procurement Plan (LTPP)

Resource Type	Track 1 LCR (D.13-02-015)	Additional Track 4 Authorization	Total Authorization
Preferred Resources (min requirement)	150 MW	400 MW	550 MW
Energy Storage (min requirement)	50 MW		50 MW
Gas-fired Generation (min requirement)	1,000 MW		1,000 MW
Optional additional from Pref Resources & Energy Storage only	up to 400 MW		up to 400 MW
Additional from any resource	200 MW	100 to 300 MW	300 to 500 MW

Source: Company filings

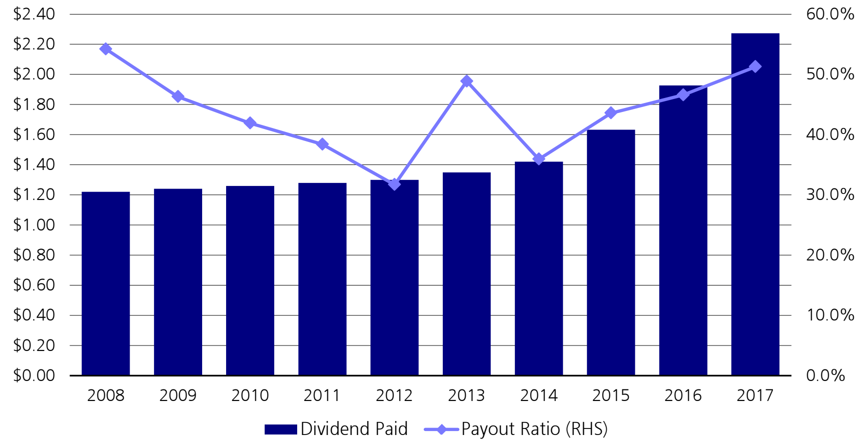
For California's energy storage initiative, about 580 MW is in EIX territory (290 MW ratebase opportunity), with 150 MW coming in a solicitation at the end of 2014. SCE is eligible to submit proposals for half the amount to enter ratebase. Recovery would come through normal ratecases (unless the project was sufficiently large enough to warrant a carve-out). Storage costs are probably in the range of $3,000-$5,000/kW today, although this will almost certainly come down over time. This is another driver of ratebase and EPS growth *above* management's current disclosed range.

The first storage procurement cycle begins in December 2014, with SCE targeting a net 14 MW storage capacity, excluding 74 MW existing and LCR storage. With some of the highest cost of storage being interconnection, we believe that SCE will have a competitive advantage over third-parties on its own territory. Presuming that the CPUC accepts SCE's existing 74 MW of storage as qualifying for the program, the remaining 62 MW of the expected total 150-MW solicitation is expected to come from third-party developers and suppliers.

"Meaningful" steps to raise dividend, probably in December

With the current dividend payout only 40% of our $3.53 estimate for 2015 vs a target payout ratio of 45%-55%, management intends to take "meaningful steps" to hike it "over time" at this December's Board meeting. We expect a 15% hike to $1.63 this year to bring the payout up to ~44% and a ~3.0% yield. We expect further large increases once the GRC is complete in 2015, reaching ~50% by 2017.

Figure 95: EIX Dividend vs Payout Ratio, 2008-2014



Source: Company filings, UBS estimates

Higher FERC ROEs likely in 2015

Management did not want to read into the latest New England case yet

We think a new (less punitive) methodology will emerge for the California utilities in particular on transmission ROE

We believe EIX is among few beneficiaries in ROE from the latest decision

Our estimates embed a few extra pennies to account for the likelihood that FERC transmission ROEs will increase in July 2015 after the moratorium on ROE is lifted. The rate was last set in a Nov 2013 settlement that granted a 9.30% base plus 50 bps for CAISO participation and another 65 bps weighted average for project incentives. The June 19th FERC order adopting a lower ROE for New England identified "the just and reasonable base ROE" as "halfway between the midpoint of the zone of reasonableness and the top", or (7.03%+11.74%)/2 = 9.39% and (9.39%+11.74%)/2 = 10.57%. Considering a somewhat more conservative method to reach this "75th percentile" would be to rank the proxy group and pick the actual 75th percentile at 9.77%. We've chosen to apply this 9.77% as the new base ROE beginning in mid-2015 for EIX. For more color on FERC ROEs from our recent trip to DC, please see our recent 7/11 note "Deciphering the DC Code".

Figure 96: EIX UBS estimates 2014E-2018E

EIX		2014		2015		2016		2017		2018
Ratebase (midpoint)		22.1		23.9		26.3		28.2		29.8
Ratebase growth				8.0%		10.0%		7.3%		5.6%
% FERC		22.0%		22.7%		23.3%		24.0%		24.7%
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 Add		0.50%		**		0.50%		0.50%		0.50%
Avg. Project Incentive Adder		0.65%		**		0.65%		0.65%		0.65%
FERC ROE		10.45%		10.69%		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		3.40		3.69		4.08		4.39		4.63
SONGS shutdown		(0.07)		(0.07)		(0.07)		(0.07)		(0.07)
Reg Asset earnings		0.03		0.04		0.04		0.04		0.04
Income tax benefit		0.14		-		-		-		-
Cost savings		0.35		-		-		-		-
Other tax benefits and FERC rev		0.24								
Energy efficiency		0.03		0.03		0.03		0.03		0.03
Parent & other		(0.11)		(0.13)		(0.12)		(0.13)		(0.15)
Total EPS (basic)		4.01		3.56		3.96		4.26		4.48
Total EPS (diluted)		3.97		3.53		3.93		4.22		4.44
Previous UBSe	*$*	*3.97*	*$*	*3.53*	*$*	*3.93*	*$*	*4.22*	*$*	*4.45*
Consensus	*$*	*3.90*	*$*	*3.58*	*$*	*3.91*	*$*	*4.20*	*$*	*4.45*

** FERC ROE 10.45% established in Nov 2013 settlement with a moratorium on ROE changes through June 30, 2015

Assume increase base ROE to 9.84% in July 2015 using 75th percentile method

Source: UBS estimates, Company filings, FactSet

Transmission and Distribution strategy coming to center stage

The settlement would clear a path toward a favorable GRC and achieving the company's 2014-2017 ratebase CAGR projection of 7%-9%.

After years of having to deal with the Edison Mission bankruptcy, the EME asset sale, and the shutdown of the San Onofre Nuclear Gen Station (SONGS), management is finally poised to devote nearly all of its attention to the core business of building, upgrading, and maintaining its regulated transmission and distribution system. As a reminder, in 2013, transmission and infrastructure delays and lower costs reduced capex $300M below forecast, with most of this spending pushed out and redistributed into 2014/5. Updated cost estimates for transmission, including new FAA requirements for the Tehachapi project, also added $100M to 2014/5 capex vs. prior forecasts. <u>Upside can still come from energy storage projects, the Orange County preferred resource pilot, and other post-2018 CAISO transmission projects.</u>

By the end of 2014, EIX plans to submit revised costs for the $3.2B Tehachapi line to reflect a preliminary $360M estimate of increased costs for Chino Hills undergrounding, FAA requirements, and other cost increases. Tehachapi is scheduled to be in-service 2016-2017, while two other large transmission projects under the utility's capital plan include the $813M Coolwater-Lugo line with a 2018 in-service date and the $1,034M West of Devers line to be in-service 2019-2020.

On the distribution side, the GRC filing is focused on infrastructure replacement and reliability (rather than load growth), which are priorities of the state and are helped by the slower pace of load growth in recent years. The 2015 GRC request represents a 120% increase in infrastructure replacement vs the 2012 GRC, with $9.3B of requested capex from 2015-2017.

Collapsing the rate tiers still not a near-term solution

Management has noted that collapsing its rate tiers in order to reduce ratepayer subsidization of distributed solar will probably take a few years, with the latest proposal calling for a fixed charge starting at $5/mo in 2015 (vs. $0.95/mo today), climbing to $7.50/$10 per month by 2016/2017, respectively; this remains pending and is likely to see resolution in 4Q. 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.

EIX continues to make the point that although distributed solar is growing rapidly, it is still a very small part of California generation and is still needed to meet RPS goals

Nothing else in the interim

In the meantime, the company would probably take other mitigating actions to relieve the burden on some non-solar customers. On the possible grandfathering of installed solar from any rate tier moves, Chairman Peevey recently opined that 20 years might be appropriate. However, this period is considered far too long by State Assembly member Perea, the author of California's AB 327 net metering law, whose constituents would be poised to benefit from lower rates under a rate tier collapse. In any case, EIX continues to make the point that although distributed solar is growing rapidly; it is still a very small part of California generation and is still needed to meet RPS goals.

Grandfathering rules may not be fully understood by customers

Even grandfathered customers will see their savings drop and their bills rise.

Under the grandfathering rules, current net metering customers in the higher tiers 3 & 4 are still going to see their monthly savings drop, perhaps by as much as half, as the grandfathering does not prevent the company from reducing the generation rate embedded within the full retail rate that is paid for rooftop generation. We believe many customers grandfathered under the old rules may believe that their payment rates are not going to change and may not appreciate the nuance in the new rules. Non-grandfathered customers will do even worse, with them only receiving the new lower generation rates rather than a full retail rate.

EIX won't pursue its own utility residential rooftop solar a la PNW

We flag that SCE is not keen on pursuing a utility-based residential rooftop program, seeing it as uncompetitive vs. broader market offerings. Their focus remains on the T&D plan under AB327 rather than any taking on the solar industry head-on.

Transporting California: Arizona competitive solicitation the focus

Excluded from its capex and ratebase forecasts are possible competitive transmission projects.

EIX intends to participate in CAISO's competitive transmission process under FERC Order 1000 that could add projects and growth above and beyond the stated $15.1B-$17.2B utility capital plan from 2014-2017. This already includes the Tehachapi line and the ~$360M Chino Hills undergrounding. Beyond this, EIX could pursue additional territorial and extra-territorial projects from CAISO 2018+ through either its utility or a new competitive transmission subsidiary. In particular, the Delaney-Colorado line is a potential opportunity which has been proposed for economic reasons (rather than engineering). While it's all very tentative for now, the project was last speculated to cost ~$400M (years ago). EIX already owns the required rights-of-way. Management thinks that CAISO's 2020 tentative in-service date is probably too aggressive considering required lead times for this type of project. For its part, the company has no public cost estimate available for this potential project yet, nor will it comment on financing plans or potential partners.

With bids submitted to CAISO in August, we expect an announcement by Oct 18 (60 day window).

But what about competitive solicitations for transmission?

This too is coming, likely with more material impacts beyond the current forecast period through 2017. The company's investment outlook does not include any capital expenditures that were exposed to competitive solicitations, clearly embedding a degree of conservatism to the extent it is successful in sourcing incremental projects. While only modestly sized projects appear to be pending before the CAISO in the current year's batch of projects, we look for EIX to increasingly participate in such efforts either through SCE or a separate competitive Transco arm. We see California as leading peer ISOs on this front, having already conducted three such processes, albeit all of them small in size.

What about energy efficiency in California?

While the current program is slated to end at year end (providing +$0.03 in management's guidance), we understand the current program for 2014 could actually result in a step up due to the accelerated realization of EE revenues (only 1-year delay rather than historic 2-years); this suggests EE could be ~$0.05.

Adequate liquidity available to fund the growth

No foreseeable need for equity to fund the capital program.

The utility is currently recovering its $1B under collection in the Energy Resource Recovery Account (ERRA) through the end of 2015 and management has no foreseeable need for equity to fund the capital program.

Empire District Electric Company (Neutral; $24 PT)

In the continued absence of rate relief, wildcard is how significant the oscillating weather will impact results.

Regulatory lag continues to hit EDE in the middle of 2014.

Empire District Electric is estimated to report 3Q14 EPS of **$0.49**, down versus 3Q13 due to the absence of rate relief YoY but still above a thin consensus ($0.41). This quarterly estimate includes ~$0.06/sh of drag for O&M, depreciation, and property taxes with the only real offset being AFUDC earnings of $0.02. Missouri weather has been volatile with a 20% decrease in CDDs in July followed by a 16% improvement in August versus the comparable 2013 period.

Empire District has not revised their guidance after providing it since 2012 when the utility was hit by the impacts of well-below normal weather in 1Q12. After incorporating these changes to its guidance, management has beaten expectations by 9% over the past two years. Our FY14 EPS estimate of $1.47 remains towards the high-end of the $1.38-$1.50 range following the $0.07/sh of positive weather in 1H14 and in the absence of a more 3Q14 significant weather hit than we anticipate, we see latitude for management to increase its guidance range by up to $0.05. Typically EDE releases its full year guidance for the upcoming year with fourth quarter results so we do not anticipate any material reason for management to deviate from this pattern. Comments on the call about any recovery of load growth could be a positive for next year's guidance but it

Figure 97: 3Q14 Earnings Walk

3Q14 Earnings Walk	EPS	Comments
3Q13A	**$0.56**	
Margin		
Rate Relief	$0.00	*Previous rates effective April 1st , 2013; no YoY uplift*
Customer Growth	$0.00	*Pretty flattish (<1%) but making progress in Joplin recovery*
Weather	($0.02)	*3Q13 weather was average; 3Q14 Mixed but cooler overall*
O&M	($0.03)	*Organic cost inflation*
Depreciation & Amort.	($0.02)	*Organic cost inflation*
Property Taxes & Other	($0.01)	*Regulatory lag*
AFUDC	$0.02	*Spending on Asbury Scrubber/Begin Spend on Riverton CT (2014 is Peak Capex Year)*
Other (Δ in Tax rate etc.)	($0.01)	*~Immaterial increase*
3Q14E	**$0.49**	
Consensus	***$0.41***	

Source: Company Filings, FactSet, UBS Estimates

Links to our relevant recent research are below:
8/7/14 Working Through the Regulatory Outlook
8/6/14 Reconciling the Earnings Growth Problem

Empire Files For New Missouri Rates

As expected, EDE's Missouri rate case is driven almost entirely by Asbury environmental costs

Empire District Electric recently filed for its long awaited Missouri rate case which captures the environmental upgrades to the Asbury unit. EDE is requesting a revenue increase of $24.3Mn and a 10.15% ROE on a 51.45% equity ratio (target is 50%/50%). The vast majority of the increase relates to the Asbury scrubber and related environmental upgrades which comprise over 80% of the net request. The case has an April 30, 2014 test year ($1.17Bn ratebase) with adjustments for

known items through year-end to capture Asbury spending.
Docket Number: ER-2014-0351

Figure 98: Empire District Electric Missouri Rate Case Rev. Requests

Rate Case Revenue Requirement Drivers		
Item	Revenue Requirement	% of Total
Asbury Environmental	19.8	81.5%
Property Taxes	2.9	11.9%
RTO Transmission Charges	1.0	4.1%
Maintenance Contract	3.9	16.0%
Other (SPP and Int. Exp Savings)	-3.3	-13.6%
Total	**24.3**	
10.15% Requested RoE		

Source: Company Filings

Cost estimate for Asbury ~unchanged.

EDE was 90% done with Asbury construction as of the 2Q14 call and expects to be complete by February 1st and captured in the rate case via a true-up. The cost was reaffirmed at $112-130Mn, essentially unchanged from earlier estimates. It is also worth noting that EDE could pursue recovery of the property taxes via an Accounting Administrative Order (AAO) as it looks for ways to reduce regulatory lag in Missouri.

Missouri is by far the most significant jurisdiction for EDE (85% of YE13 ratebase) but on September 29th the Arkansas PSC approved the $1.37Mn revenue increase for the company along with its existing trackers.

Private debt issuance could come in next few months

EDE does not have any real financing maturities before 2018 ($90Mn in 2018 and $100Mn in 2020) and is still planning on a $50Mn private debt financing in the upcoming months. Additional debt could be issued in 2015

The key question for management is what comes after this case?

With management narrowly focused on executing on both completion of the scrubber as well as the pending case, the most important questions remain what is management to do subsequent to this execution-related task. We emphasize the company's strategic outlook on how to deliver growth to shareholders remains among the most stark in smid-cap sector. Aside for social, regulatory, and valuation hurdles, the company appears to be among the most logical sale targets.

Figure 99: EDE remaining assets after Riverton Unit 7 retirement

Asset	State	Owned Capacity	Status	Fuel
Asbury	MO	189.0	Operating	Coal
Empire Energy Center	MO	262.0	Operating	Natural Gas
Iatan	MO	84.6	Operating	Coal
Iatan 2	MO	105.7	Operating	Coal
Ozark Beach	MO	16.0	Operating	Water
Plum Point Energy	AR	100.4	Operating	Coal
Riverton	KS	241.5	Operating	Natural Gas
State Line CC	MO	297.0	Operating	Natural Gas
State Line CT	MO	94.0	Operating	Natural Gas
Total		**1,390.2**		

Source: SNL and Company Filings

Valuation: Maintain $24 Price Target

Our valuation is derived via a 2015 median P/E using a small-cap peer group. Despite the prospects of legislative reforms in Missouri to reduce regulatory lag having lost steam as of late, the possibility of M&A should continue to support shares.

Maintaining $24 PT on lower peer multiple. Price Target would remain at $24 even if removing Cleco from the comp set (would cause median to decline from 15.4x to 15.2x).

Figure 100: EDE Valuation

EDE Price Target 'Base Case'		
EPS	$1.56	2015 UBSe
x	15.4x	2015 P/E Multiple
	$24.09	**Official PT**

EDE Price Target 'Low Case'		
EPS	$1.56	2015 UBSe
x	14.9x	Discounted '15 P/E
	$23.31	

EDE Price Target 'Upside Case'		
EPS	$1.56	2015 UBSe
x	15.9x	Premium '15 P/E
	$24.88	

Source: Company Filings, FactSet, and UBS Estimates

Our EPS estimates are slightly higher throughout the horizon.

Figure 101: EDE EPS Estimates

EDE EPS Estimates	2014E	2015E	2016E	2017E	2018E
UBS estimates	$1.48	$1.56	$1.62	$1.67	$1.72
Guidance	$1.38-$1.50				
Prior *estimates*	$1.47	$1.55	$1.59	$1.64	
Consensus estimates	*1.46*	*1.54*	*1.64*	*1.75*	
Implied Earned ROE					
Using Ratebase Math	*7.79%*	*7.86%*	*7.89%*	*8.19%*	*8.60%*
Using GAAP Average	*8.26%*	*8.36%*	*8.41%*	*8.50%*	*8.63%*

Source: Company Filings and UBS Estimates

Figure 102: EDE Comp Set – 15.4x Median 2015E P/E

		UBS	Market Cap	Price	Dividend	Payout Ratio			EPS			P/E			
Company	Tkr	Rating	($ mill)	10/14/2014	Yield	2013A	2014E	2015E	2014E	2015E	2016E	2013A	2014E	2015E	2016E
Black Hills Corp	BKH	NR	$2,192	$49.11	3.18%	63%	56%	57%	$2.77	$2.82	$2.98	20.2x	17.7x	17.4x	16.5x
Cleco Corp	CNL	NR	$2,901	$48.05	3.33%	57%	59%	67%	$2.67	$2.70	$2.96	19.0x	18.0x	17.8x	16.2x
El Paso Electric	EE	NR	$1,465	$36.31	3.08%	NA	48%	50%	$2.33	$2.38	$2.62	16.5x	15.6x	15.3x	13.9x
Idacorp	IDA	NR	$2,886	$57.42	3.27%	NA	NA	NA	$3.56	$3.48	$3.70	15.8x	16.1x	16.5x	15.5x
The LaClede Group	LG	NR	$2,081	$48.21	3.65%	60%	58%	58%	$3.04	$3.16	$3.30	16.8x	15.8x	15.2x	14.6x
MGE Energy	MGEE	NR	$1,409	$40.64	2.78%	NA	NA	NA	$2.10	$2.20	$2.30	18.8x	19.4x	18.5x	17.7x
NorthWestern Corp	NWE	NR	$1,925	$49.18	3.25%	62%	59%	58%	$2.69	$3.19	$3.43	20.0x	18.3x	15.4x	14.3x
Otter Tail Corp	OTTR	NR	$1,056	$28.81	4.20%	76%	69%	68%	$1.75	$1.81	$1.96	18.5x	16.5x	15.9x	14.7x
South Jersey Industries	SJI	NR	$1,844	$55.66	3.40%	59%	57%	58%	$3.37	$3.49	$3.88	18.4x	16.5x	16.0x	14.3x
UIL Holdings	UIL	NR	$2,182	$38.58	4.48%	76%	76%	71%	$2.28	$2.44	$2.60	16.9x	16.9x	15.8x	14.8x
Unitil Corp	UTL	NR	$468	$33.69	4.10%	88%	78%	74%	$1.78	$1.87	$1.99	21.5x	18.9x	18.0x	16.9x
Average					**3.52%**	**67%**	**62%**	**62%**				**18.4x**	**17.3x**	**16.5x**	**15.4x**
Median					**3.33%**	**62%**	**59%**	**58%**				**18.5x**	**16.9x**	**16.0x**	**14.8x**
Empire District - UBS	**EDE**	**Neutral**	**$1,122**	**$25.87**	**3.94%**	**66%**	**70%**	**68%**	**$1.47**	**$1.55**	**$1.59**	**16.8x**	**17.6x**	**16.7x**	**16.3x**

Source: Factset, Company Filings and UBS estimate for EDE

Entergy (Neutral; $77 PT)

We look for an in-line pre-release. We think EEI will be meaningfully quieter than usual given lack of explicit EPS guidance, but suspect specific expectations on 2015 sales growth (likely disclosed driver) along with capex (unclear if this will move much following recent analyst day).

We look for the company to pre-report relatively in-line with Street expectations – at **$2.09** vs. consensus of $2.15. While pre-tax results could tend to be a bit weak, we consistently suspect a slightly better than full consolidated tax rate could yet offset some pressures. The company benefitted from slightly better rates YoY in Texas, but had limited increases associated with its latest Arkansas rate case.

Expect release today?

Figure 103: When will they pre-report?

Preliminary 3Q Result Dates		
2014	15-Oct	Wed
2013	15-Oct	Tues
2012	15-Oct	Mon
2011	19-Oct	Tues
2010	15-Oct	Friday
2009	15-Oct	Friday

Source: Company reports

Figure 104: 3Q YoY Walk

3Q13A	**2.41**
3Q13 Adjustments	
EWC state inc tax benefit	(0.40)
Normal Items	
EWC	
EWC Depn	(0.06)
Decomm Expense	(0.01)
No refueling outage days in 3q13 in 3q14, less unplanned	0.02
EWC Margins (Energy & Capacity)	0.16
O&M - EWC	0.01
Utility	
Weather Reversal from 3Q13	0.01
Weather vs. Normal 3Q14	(0.05)
Other Income - Biased 1H14	0.02
Utility Depn	(0.04)
O&M - Utility	0.06
O&M from Stator accident at ANO last year	-
Income taxes at the utility 33% last year vs higher	(0.04)
ETR TX Increase April 2014	0.02
ETR - Ark - > No Real Change	-
System Energy - Grand Gulf Nuclear declining ratebase	(0.02)
Net Changes	***(0.32)***
3Q14E	**2.09**
Consensus	***2.15***
2014 Guidance	***5.55-6.75***

Source: Company reports and UBS estimates

Links to our relevant recent research are below:
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

Updated Entergy Estimates

We include our latest estimates below, revised upwards due to the latest rally in New York and New England commodity prices. We emphasize that while they are off a bit of late, the overall trend puts Entergy back into achieving its contemplated 2-4% EPS growth rate delineated at its Analyst Day earlier this year. We believe estimates will continue to swing with the commodity volatility such that this guidance is relatively less helpful than pure-play regulated peers.

Figure 105: Entergy EPS estimates

EPS by Segment	2012A	2013A	2014E	2015E	2016E	2017E	2018E
Regulated Utility	5.50	4.80	5.04	5.47	5.81	6.27	6.55
EWC/Nuclear	1.49	1.47	2.06	0.73	1.02	0.62	0.53
Other	(0.76)	(0.91)	(1.06)	(1.05)	(1.00)	(1.01)	(1.03)
Consolidated	6.23	5.36	6.04	5.15	5.82	5.87	6.05
Previous	6.23	5.36	6.03	5.10	5.57	5.58	
Guidance Range		4.60-5.40	5.55-6.75				
EPS CAGR (2013A-2016)		Guidance	2-4%	UBSe	2.80%		
Consensus			6.15	5.32	5.65	5.78	

Source: Company reports and UBS estimates

Valuation: $77 Price Target

Our utilities sum-of-the-parts valuation is below where we continue to apply a discount to nuclear business (4x EV / EBITDA) relative to peers.

Figure 106: SOP Valuation

All figures in US $ million except per share data	2016E NI/EBITDA	EV/EBITDA and P/E Multiple					
			P/E Multiple			Equity Value	
	2016 EPS	Low	Base	High	Low	Base	High
		2016 Peers	14.8x				
Regulated Utility (Consolidated)	5.81	13.8x	14.8x	15.8x	80.12	85.92	91.73
Parent Preferred Income	(0.39)	13.8x	14.8x	15.8x	(5.44)	(5.83)	(6.22)
Other Parent Exp (non-Pfd)	(0.22)	13.8x	14.8x	15.8x	(3.09)	(3.32)	(3.54)
Utility Value: T&D Segments	5.19	*13.8x*	*14.8x*	*15.8x*	71.59	76.77	81.96
Total Utility Equity value per share					$71.59	$76.77	$81.96
EWC Value is a Proxy for NPV of Hedges / Indian Point			EV/EBITDA Multiple			Enterprise Value	
	2016 Adj. EBITDA	Low	Base	High	Low	Base	High
Nuclear and Wholesale Gen	651	3.0x	4.0x	5.0x	$1,954	$2,606	$3,257
Hedges	(13)	3.0x	4.0x	5.0x	(39)	(53)	(66)
Total / Implied	638	*3.0x*	*4.0x*	*5.0x*	$1,915	$2,553	$3,191
Parent + EWC Debt						(3,041)	
Less: Parent + EWC Cash						152	
FCF through end '15						449	
Net Debt (Parent+EWC)						(2,439)	
Add/(Subtract): Hedge Value NPV						(14)	
Subtract NYPA Value Sharing payment (expires 2014)						(72)	
Merchant Generation Equity Value/(Drag)					(538)	28	738
Current Number of Shares outstanding					179	179	179
Merchant Generation Equity value per share					($3.01)	$0.16	$4.14
Total Equity Value per Share					$68.57	$76.93	$86.10

Source: Company reports and UBS estimates

Till when will Vermont Yankee run? Up until the end.

We believe Entergy will opt to run Vermont Yankee up until *near* the end of its deal with the state on its operating license on December 31st, 2014 given the

potential profitability of the unit through the late part of the year. We emphasize a need to balance the plant's fuel capabilities against its dispatch.

Is LHV under some pressure? Both near and long term.

We emphasize prices have generally peaked both in New York – as Danskammer is poised to push down pricing this winter/next year. Meanwhile, we see further structural risk to prices in the long-term from a further transmission build-out, potentially putting at risk the constraints involved with the LHV Zone; we look for more details on this front from ConEd/the NY PSC in 2015, following the latest gubernatorial election.

We emphasize New York prices may *not* be under as much pressure given the latest proposed PJM reforms, driving units to withdraw from exporting to New York in favor of maintaining it in NJ and PA. This could specifically improve the pricing in New York City (Zone J).

Please read our latest note, *Dropping the Danskammer on New York*.

Capex: Update With EEI Likely

Updates on utility capital expenditure were largely reflected in the recent Analyst Day, delaying the White Bluffs scrubber beyond the forecast along with a few other tweaks. The cumulative number for the 5-year period is $10-11 Bn released at its Analyst Day.

EWC guidance was not updated at its Analyst Day – and is likely to be with the latest EEI preliminary forecast.

Transmission: was up slightly at the Analyst Day, but still the focus

We think this will remain the focus of the future utility growth, with the Analyst revision for $1.8Bn through the 3-year period, vs. $1.7 Bn previously. Entergy is working on its first iteration of the process for both MISO and the FERC 1000 initiative, however, much of this contemplated incremental spend would be beyond the 3-year outlook. There remains modest potential for upside on spend.

Sales growth is a closely watched driver. Specific guidance on 2015 is worth watching, following its 3-year 3.5-3.75% CAGR for sales growth released at its Analyst day earlier.

Regulated Activities:

Big regulatory change in Arkansas worth watching

We emphasize ahead of a renewed push by Entergy to engage regulators in this jurisdiction, we emphasize a tight Governor's race between Asa Hutchinson (R), and Mike Ross (D). The current Governor, Mike Beebe (D) is term limited.

New governor will have sizable influence on Arkansas commission

Complete turnover on 3 member commission

We emphasize any new governor would have the ability to appoint three new positions, given an already elapsed position, Reeves whose term is up in January, and Honorable who was recently nominated to

Without a rate case in Arkansas, talks to start

Given the substantial changes at the Commission, we see the next several months as key to improving the tone of the relationship with regulators. The state remains of the utmost importance in driving an improved earnings trajectory – addressing rate lag, as well as potentially seeking trackers.

Opportunity to engage new Commissioners.

Mississippi rate case continues, but don't expect much change

We think the rate case will be concluded to little fanfare, however, an updated ROE always remains a key focus of any case; this is particularly true following a recent decision by the AR commission to lower Entergy to 9.4%, and subsequently 9.8% upon rehearing. The states' Formula Rate Plan (FRP) mechanism to remain in place, limiting future rate case exposure, with the reason for the latest case predicated almost entirely by the need to change tariffs to reflect joining MISO.

Louisiana combination study filed, kickstarting merger process

Entergy recently filed to move forward with the merger of its Gulf States and ETR-Louisiana subsidiaries in the state, given anticipated the cost savings. The two utilities now have the same capitalization structure and authorized ROE; a challenge will likely be working on uniform rate design (i.e. one residential rate for all customers) Although most customers should save, some customers could see higher bills due to the combination. Entergy will need to address bill shock and would likely have phased-in rates for those impacted customers.

Simply a cost saving exercise – no EPS benefit.

What does the PSC look for in a merger? Benefits to be passed through

Despite being a merger of two Entergy subsidiaries, management's proposal to consolidate operations will still undergo a full merger proceeding. For Entergy the focus as mentioned above would be primarily on rate design and ensuring that there are overall benefits.

PSC will look for impact on customer bills, reliability, local jobs, and the financial health of the company offering to buy

Rate design could heighten tensions

We see a variety of rate design issues as potentially straining its regulatory dynamic. While unlikely to prove too much of a hurdle, we emphasize forthcoming merger filing of Entergy Louisiana-Entergy Gulf States Louisiana (ELL-EGSL) at the end of September, and ongoing rate case in Mississippi to implement MISO rates as examples. Lastly, we emphasize the ongoing system agreement exit (potentially expedited to a 5-year transition vs. 8-years under current rules), as driving rate evolution across all its territories; only Louisiana would remain today (AR, MS, and TX have all filed notice to exit). We suspect its utilities in the state (New Orleans, ETR-Louisiana, and ETR-Gulf States) could yet negotiate a consensual exit (as part of the upcoming ETR-LA and ETR-GS mergers?); the remaining question would be how this impacts rates in New Orleans (City Council jurisdiction continues to limit folding of this tiny utility into the remainder of the company). We emphasize the Formula Rate Plan (FRP) filings are likely to remain in place across the jurisdictions – and don't see meaningful need for rate relief for the time being irrespective. Rather, for rate tariffs negatively impacted, we look for transition periods to assuage concerns.

Exelon Corp. (Neutral; $35 PT)

Quarter could be above guidance range and FY14 expectations could be lifted as well. ExGen MTM shows reversal of some Summer losses but still down $50/$100Mn on '15/'16 since 6/30 GM guidance.

Quarter above the guidance range and could bring a positive FY14 EPS guidance revision up $0.10 at the low-end.

We project 3Q adjusted EPS of **$0.71**, above the top end of its guidance range of $0.60-0.70, and seemingly in-line with the Street consensus of $0.72. We flag the strong results appear to be driven in part by management's ability to insulate its utilities from the weather and overall see them as flat YoY (vs +$0.02 YoY in 2Q14). The comparative results are pulled down by lower energy margins and capacity pricing at ExGen albeit offset slightly by the nuclear fuel disposal fee reduction.

Exelon could tighten its EPS range to $0.20 by lifting the bottom end of its range by $0.10 to **$2.35-$2.55**. We expect FY14E EPS of $2.45, $0.06 above consensus.

Figure 107: EXC 3Q YoY EPS Walk

EPS	
$0.78	**Proforma 3Q13A Reported EXC+CEG**
0.00	**BGE Contribution**
0.01	*Rate Increase ($130 Mn) effective late Feb*
(0.01)	O&M Offset
0.00	**PECO**
0.00	Limited Load growth: +0.2% Residential forecast for 2014
0.02	Return to normal tax rate
(0.01)	Weather Impact: ~20% decline in CDDs [Only Utility w/ Exposure]
(0.00)	**ComEd**
0.01	Revenues net of Fuel, including Senate Bill 9
(0.01)	30-year Treasury Trend (slight negative)
(0.01)	D&A
(0.07)	**ExGen YoY Factors**
(0.07)	Lower energy margins (offset by volatility benefits)
(0.01)	Capacity
0.03	Nuclear fuel (amortization offset by disposal fee reduction)
0.01	Benefits from serving from market for retail load
(0.01)	Other
(0.00)	D&A
(0.01)	O&M Inflation, D&A, Pension and OPEB, non-power
$0.71	**3Q14E EPS Estimate**
0.72	***Consensus***
$0.60-0.70	***Guidance range for the quarter, flat YoY***
863	Shares Outstanding

Source: Company reports and UBS estimates

Links to our relevant recent research are below:

9/30/14 Doing the Texas Two Step
8/25/14 Deploying Capital, One Asset At a Time
8/4/14 Power Crossroads: Still Not Quite the Time
7/30/14 "Getting Back" to Guidance
6/24/14 Nuclear Politics
5/1/14 How to Think about EXC Beyond the Deal?

ExGen Gross Margins Recovery $100/$150Mn in 2015/2016 on Latest MTM But A Guidance Cut Still Looks Necessary

Power prices have improved since July 30th but are still modestly lower than they were in April.

Exelon Generation (ExGen) lowered its hedged gross margin guidance (as of 6/30) for 2015/2016 by $50/$150Mn from with 2Q results versus its 'mid-quarter' update (4/30) following the ~$3-4/MW-Day declines in key hubs. Since then we have seen solid recovery across the board, which reduces the declines; however, we still see management lowering its ExGen hedged gross margin guidance by $50Mn and $100Mn in 2015 and 2016, respectively:

- **2015**: We expect guidance to be reduced $50 to $7,700Mn from $7,750Mn
- **2016**: We expect guidance to be reduced $100 to $7,650Mn from $7,850Mn

Figure 108: ExGen Gross Margin Analysis (Aug 4 Note)

Hedged Gross Margin ($Mn)	2015	2016
Old Guidance (4/30/14)	$7,800	$8,000
New Guidance (6/30/14)	$7,750	$7,850
April-to-June Declines	($50)	($150)
NI Hub Down ~$3.10	($90)	($186)
PJM W Down ~$3.05	($46)	($116)
NY-Zone A Down ~$3.60	($11)	($11)
Decline in Power 6/30-7/30	($146)	($313)
MTM + EXC Guidance	$7,604	$7,537
UBSe (7/30/14 Pricing)	$7,606	$7,500
UBSe vs EXC MTM	$2	($37)

Source: Company Filings and UBS Estimates

Figure 109: ExGen Gross Margin Analysis (Updated)

Hedged Gross Margin ($Mn)	2015	2016
Old Guidance (4/30/14)	$7,800	$8,000
New Guidance (6/30/14)	$7,750	$7,850
April-to-June Declines	($50)	($150)
NI Hub Down ~$1.40; $2.50	($40)	($148)
PJM W Down ~$0.90; $1.30	($13)	($51)
NY-Zone A Down ~$0.40; $1.10	($1)	($3)
Decline in Power 6/30-10/10	($54)	($202)
MTM + EXC Guidance	$7,696	$7,648
UBSe (10/8/14 Pricing)	$7,697	$7,649
UBSe vs EXC MTM	$0	$1

Source: Company Filings and UBS Estimates

Exelon's generation sensitivities have continued to decline through the 6/30 update as management opts to increase hedging and the wildcard will be how much management opted to hedge in the mild summer with weaker prices. It appears that Exelon was more confident about PJM-West prices recovering, especially for 2016, as the sensitivities were minimally changed since the end of April. In contrast, NiHub 2016 sensitivities have declined by over 25% since 3/31.

Figure 110: Changes in NiHub Sensitivities

As of 3/31/14	Declining sensitivities	
NiHub ATC Energy Price	2015	2016
+$5/MWh	250	380
-$5/MWh	(245)	(375)
As of 4/30/14		
NiHub ATC Energy Price	2015	2016
+$5/MWh	235	360
-$5/MWh	(230)	(360)
As of 6/30/14		
NiHub ATC Energy Price	2015	2016
+$5/MWh	150	300
-$5/MWh	(145)	(300)

Source: Company Filings

Figure 111: Changes in PJM-West Sensitivities

As of 3/31/14	Declining sensitivities	
PJM-W ATC Energy Price	2015	2016
+$5/MWh	125	220
-$5/MWh	(120)	(210)
As of 4/30/14		
PJM-W ATC Energy Price	2015	2016
+$5/MWh	90	195
-$5/MWh	(85)	(190)
As of 6/30/14		
PJM-W ATC Energy Price	2015	2016
+$5/MWh	85	195
-$5/MWh	(75)	(190)

Source: Company Filings

On a longer-term basis, the second quarter hedging increase was substantial but this simply puts Exelon approximately in-line with its +1/+2 forward hedging strategy as of 2Q13. To reiterate, this is consistent with managements statement that it was ~15 percentage points under-hedged starting the year.

Figure 112: Changes in ExGen Hedging Over Time

ExGen Hedging Disclosures				
	2Q13	*11/8/2013*	*1Q14*	*2Q14*
2013	96-99%	97-100%	N/A	N/A
2014	78-81%	84-87%	91-94%	92-95%
2015	41-44%	48-51%	64-67%	75-78%
2016	N/A	19-22%	37-40%	46-49%

Source: Company Filings

Building Some, and Selling Others

EXC has sold the bulk of the pending non-core gas assets with the coal still on the block.

We wrote a note discussing the sale of Fore River to Calpine earlier this summer and continue to track Exelon's non-core asset sales. The remaining assets include Hillabee, and the jointly-owned Keystone/Connemaugh coal units. In the case of these examples, we see the assets individually as challenged rather than having too much of a read on the markets themselves. We also see greater asset divestiture as providing greater veil of equity financing for the POM, rather than using more HoldCo leverage.

- Hillabee: This is a legacy CEG asset, which appears to be a non-core region for the company. We suspect ExGen will continue to unwind offtake commitments and generation in non-core regions as contracts expire (such as the legacy PGN deal). ExGen maintains several PPA'd assets in Southeast to meet load obligations from Tenaska which rolloff in coming years (and are unlikely to be extended either). We also see timing on this sale as predicated off the latest Calpine sale price for its portfolio to LS Power, seeing this as exceptionally accretive to EXC.

- Fore River *Sold to Calpine*: This dual fuel unit seemingly has gas procurement issues in New England, limiting its ability to compete in the market place. As such, we understand this is the most dis-advantaged of the BostonGen portfolio. For further details on this transaction please refer to our note, **'Deploying Capital, One Asset At a Time'**.

- Keystone/Conemaugh: Only reiterating our more cautious view on NAPP coal generation in PA, we see it is as indicative management is seeking to sell-down its partial stake in the plants (even if they are entirely controlled with scrubbers and SCRs). We suspect prices will remain under pressure for these plants. We suspect buyers would be most likely a private equity entity, seeing the risk profile and FCF. Another co-owner could up the stake as well (NRG?), but unlikely in our view.

- Quail Run *Sold to Starwood*: Management appears more down on this asset given the limited capacity factor of the asset, in part due to growing wind penetration in ERCOT-North. We don't necessarily read too much into this regarding its broader market view, but caution that it reads quite cool on interest in EFH's coal portfolio in the same market.

- West Valley *Pending Sale*: Exelon has filed with the FERC to sell its interest in the 205MW natural gas plant in Utah to Wayzata Investment Partners. Media reports have stated that a sale is in the $70-90Mn range.

We estimate that Exelon could raise ~$1.5Bn from these additional asset sales and believe that there would be minimal tax leakage given that the gas assets are relatively new.

Figure 113: EXC Assets 'On-the-Block'

Potential Non-Core Assets for Sale						
Asset	*MW*	*In-Service*	*Type*	*Location*	*$/kW*	$Mn
Fore River	809	2003	CCGT	MA	$655	530
Quail Run	488	2007	CCGT	TX	$300	146
Hillabee	798	2010	CCGT	AL	$500	399
Keystone*	714	1967	Coal	PA	$250	179
Conemaugh*	532	1970	Coal	PA	$250	133
West Valley	205	2002	Gas CT	UT	$375	77
				Total		**1,464**

Source: Company Filings and UBS Estimates *Jointly Owned (Represents EXC's share)

Adding 2GW of TX supply speaks louder than divesting 500MW of west TX generation.

While management has opted to sell its Quail Run CCGT for ~$150Mn, its decision to build an additional 2GW in the state confirms its earlier statement that it remains constructive on the ERCOT market Rather, we attribute this asset sale to a depressed outlook from the negative effect of renewables (driving this asset's outlook down to a mid-to-high teen CF based on recent years, with management somewhat bearish on renewables). We emphasize that the 2GW, $1.4Bn (~$700/kW) price is based on a clear cost advantage over peers. The company is able to take advantage of its existing sites and economies of scale between the two locations (~250 miles away). Additionally, it is likely that management was able to secure a good deal on the new turbines from GE.

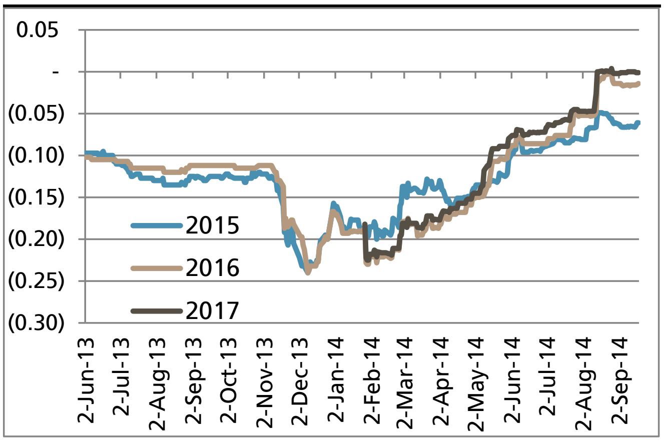
Texas Gas Basis Shows Real Improvement – And Contango

Is power recovery driven in part by gas price improvement- in Texas?

Below we present recent increases for gas basis, both for Western Texas (WaHa) and the Houston ship channel. We continue to expect significant appreciation in regional gas basis as plans for both significant increased usage within the state as well as exports to Mexico influence historic flows – and costs. The meaningful contango emerging in 2016/17 over 2015 illustrates the load growth phenomenon we continue to expect in the state as well

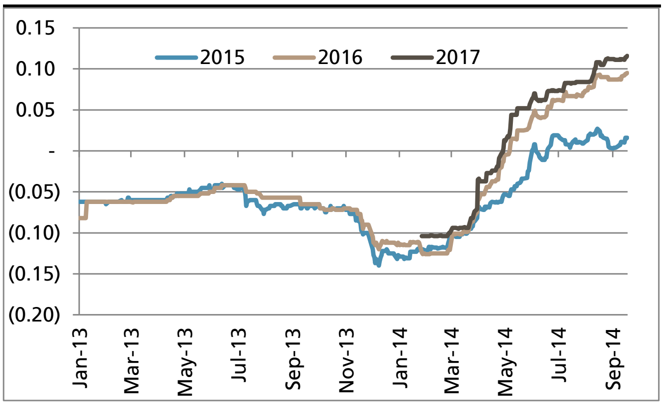
This appears to be an overall threat to the spark spread story in Houston to pay attention to.

Figure 114: WAHA [West Texas] Gas Basis ($/MMbtu)



Source: Platts

Figure 115: Houston Ship Channel Gas Basis ($/MMbtu)



Source: Platts

Following the Texas Two Step, Reviewing the Market

Following Exelon's latest announcements, its merchant arm is estimated to have 5.3GW of capacity in ERCOT, or 6.7% of the market. This compares with ~79GW of net Summer resources projected for ERCOT by 2018 from a Brattle Report released earlier this year (likely does not reflect the latest capacity additions). While Exelon has the smallest footprint out of the IPPs (excluding Dynegy which has zero generation in Texas), it still has a sizable concentration in the market. Luminant remains the dominant generator in the state with 15.4GW of ERCOT capacity (~20%); we believe that even if Exelon were to bid for Luminant as part of the EFH pending bankruptcy, it would face market power issues and have to divest assets.

Collectively Exelon and Luminant would control ~25% of the market, likely drawing concentration challenges in an M&A scenario.

Despite its historic interest in corporate M&A in Texas (a la its failed bid for NRG), we do not see it as meaningfully interested in TXU/EFH following its recent Chapter 11 filing. We think investor valuation expectations coupled with concerns on renewables in the medium term are likely to keep Exelon from bidding aggressively. Moreover, limitations on maintaining its investment grade balance sheet remain front and center.

Figure 116: Exelon Texas Capacity and ERCOT Concentration Analysis

Exelon Texas Capacity						
Station	**Region**	**Location**	**# of Units**	**Fuel Type**	**Primary Dispatch**	**Net MW**
Wolf Hollow 1, 2, 3	ERCOT	Granbury, TX	3	Gas	Intermediate	705
Mountain Creek 8	ERCOT	Dallas, TX	1	Gas	Intermediate	565
Colorado Bend	ERCOT	Wharton, TX	1	Gas	Intermediate	498
Quail Run	ERCOT	Odessa, TX	1	Gas	Intermediate	488
Handley 3	ERCOT	Fort Worth, TX	1	Gas	Intermediate	395
Handley 4, 5	ERCOT	Fort Worth, TX	2	Gas	Peaking	870
Mountain Creek 6, 7	ERCOT	Dallas, TX	2	Gas	Peaking	240
		Total ERCOT (as of 12/31/13)				**3,761**
2014 Texas Activity						
Announced New Build						
Wolf Hollow 4	ERCOT	Granbury, TX	1	Gas	Intermediate	1,000
Colorado Bend 2	ERCOT	Wharton, TX	1	Gas	Intermediate	1,000
Announced Sale						
Quail Run	ERCOT	Odessa, TX	1	Gas	Intermediate	(488)
		Total Adjusted ERCOT Capacity				**5,273**
Whitetail	Other	Webb Co., TX	57	Wind	Base-load	92
Exelon Wind 4	Other	Hansford Co., TX	38	Wind	Base-load	80

ERCOT Concentration for Select Generators	**MW**	**% of ERCOT**
Exelon	5,273	6.7%
NRG Energy	11,286	14.3%
Calpine	9,594	12.2%
Luminant	15,427	19.6%
ERCOT Net Resources (MW)	78,674	

Source: Company Filings, SNL, and UBS Estimates

Do the PJM reforms put IL legislative and OH PPAs on ice? Potentially

Given the significant uplift form the reforms for the capacity market, we think the timeline for legislative reform in IL could yet be delayed as could potential PPAs in Ohio. Notably we see higher capacity prices as making even a modest 'clean energy standard' in IL as a palatable solution to the nuclear generator deficit, particularly if revenues are increased gradually beginning in ~2016. As for Ohio, a PPA could still be approved seeing it as essentially a fixed-for-floating swap on energy & capacity revenues, making the fixed compensation provided by the state 'more in the money'. We note the onus to implement either program to 'save' the industry or specific plants will clearly be reduced with higher compensation. Timing in IL had previously anticipated legislation by next May, whereas FE and AEP had asked the PUCO for action by April and June, respectively (although an FE settlement appears targeted for ~Jan). On the PJM front, transition auctions are anticipated to be held in the 'Spring', assuming FERC approves PJM's 205 tariff filing.

Next Datapoints on Ginna Coming Soon as Intervenors Mount

Exelon filed a petition with the NY PSC on July 11th requesting that Iberdrola subsidiary Rochester Gas and Electric (RG&E) negotiate with EXC on an agreement for the 580MW Ginna Nuclear plant. It is expected the EXC and RG&E will submit terms of a reliability agreement with the PSC before December 1st.

No update on the outlook for Ginna with 2Q results. The next data point will be a joint reliability agreement filed later this year

Exelon has not submitted a formal recommendation to close Ginna to its Nuclear Group's board and ultimately we believe the PSC will help negotiate a bilateral arrangement; we believe this unit may realistically only have a few years left, with the state amenable to retaining the asset only through an interim RMR period in which it is needed for reliability (no more than ~5-years max, implying a ~2018 sunset). We suspect any deal would be similar to the existing contracts NYISO has approved on interim basis for the states' coal plants, including Cayuga. Ginna did not come up on the 2Q14 call as investors continue to focus more on the aforementioned Illinois nuclear assets. During our visit with Exelon management this summer they struck a decisively more cautious tone around the single-unit plant followings the PPA expiration in June and it looks like a wait-and-see situation for the balance of the year.

We don't think this asset has a long-life left to it

The latest chapter relates to the abovementioned fact that Exelon has not filed with NYISO to formally close the plant following the reliability study. Entergy, NRG Energy, and New York City have all filed similar complaints that granting a Reliability Support Services Agreement (RSSA) is premature. Case No. 14-E-0270

Intervenors challenge whether the plant can get RSSA payments without formally filing an intent to retire.

First Deal Approval Secured; Four To Go

On October 7th the Virginia State Corporation Commission approved the pending merger which continues to progress through the regulatory process. On the Federal front EXC stated on September 5th that it had to refile some Hart-Scott-Rodino filings.

Essentially management views transaction approval as much less of an uphill battle utilizing the knowledge gained from the Constellation merger.

EXC Offers Bulk of Merger Savings in Maryland

Exelon filed for merger approval with the Maryland Public Service Commission on August 19th where it committed no net involuntary merger related job losses of Pepco and Delmarva Power utility employees for at least two years post-merger, besides committing $100MM towards customer investment fund following the closing of the merger. The funds can be used for bill credits, assistance for low income customers and other energy efficiency measures and as per guidelines set up by PSC. 40% of the proposed fund would serve Pepco and Delmarva Power customers in Maryland. Additionally, Exelon has committed to provide $50 million over 10 years to charitable organizations and programs in the communities the PHI utilities serve. All in all, over the next ten years, EXC would share $150M of its savings out of the merger with the customers and ~40% of those would benefit customers in Maryland (assuming EXC would provide 40% of the charitable amount to MD).

Bulk of merger savings will go to Maryland customers, consistent with the sales split.

We analyzed POM's actual as well as projected distribution sales data from 2012 to 2018 (see figure below), besides analyzing actual power delivery electric customer numbers for 2012/2013 (see figure subsequent figure). Our analysis suggests sharing of 40% of the total saving with MD customers largely proportional to POM's distribution sales (GWh) in MD and number of customers served (in '000s) in MD.

Figure 117: Distribution Sales (GWh)

Distribution - GWh Sales	2012A	2013A	2014E	2015E	2016E	2017E	2018E
Pepco	26021	25822	25964	25980	26080	26160	26211
Delmarva Power & Light Company	12732	12434	12282	12318	12341	12354	12314
Atlantic City Electric Company	9429	9221	9117	9124	9160	9179	9154
PHI Power Delivery	**48182**	**47477**	**47363**	**47422**	**47581**	**47693**	**47679**
Pepco - MD	14832	14719	14659	14675	14749	14801	14830
DPL-MD	4202	4228	4156	4134	4127	4124	4107
Total - MD	**19034**	**18946**	**18815**	**18809**	**18876**	**18925**	**18937**
% MD	40%	40%	40%	40%	40%	40%	40%

Source: Company reports and UBSe

Figure 118: Power Delivery Electric Customer Analysis ('000s)

Power Delivery Electric Customer Analysis ('000s)	2012A	2013A
Pepco	**793**	**801**
District of Columbia	260	264
Maryland	533	537
Delmarva Power & Light Company	**503**	**506**
Delaware	303	305
Maryland	200	201
Atlantic City Electric Company	**545**	**545**
New Jersey	545	545
PHI Power Delivery	**1841**	**1852**
Maryland Total	733	738
% Maryland	40%	40%

Source: Company reports

This summer management characterized itself as 'cautiously optimistic' on the prospects for deal approval and stated that thus far, all talks have been constructive and positive. It appears that Exelon is taking the lessons learned from the Constellation merger to heart in a few key areas. First, the company has signed extensions for its major unions (primarily three-year deals) to secure the important support of labor. Another key has been proactively reaching out to all stakeholders (both big and small) to hopefully stem any issues before they could become bigger issues. Keeping the focus on consumer benefits has been a strategy for management, especially in Maryland and Washington DC where regulators are particularly sensitive to rate inflation. In Washington DC in particular, management noted that previous rate cases have often focused on jobs and the ability to minimize rate increases on the most cost sensitive customers.

Aside from Maryland, we view New Jersey as the remaining key regulatory approval but Washington DC and Delaware have to also approve the proposed transaction.

The PEPCO deal is still expected to close in 2Q/3Q15 and we estimate ~$2/sh of accretion (calculated later in the report) which has not been included in our valuation. For further details on the pending acquisition of PEPCO, please refer to our note **'Set to Acquire PEPCO in All-Cash Deal'**.

Updated EPS Estimates

We include our latest EPS estimates below, reflecting the latest MtM on estimates for power and gas.

Figure 119: Exelon EPS estimates

Exelon Consolidated EPS	2014	2015	2016	2017	2018
PECO	0.46	0.47	0.48	0.50	0.53
ComEd	0.58	0.65	0.69	0.73	0.79
BGE	0.22	0.22	0.23	0.24	0.25
Exelon Generation	1.21	1.50	1.38	1.31	1.39
Other	(0.03)	(0.03)	(0.01)	(0.00)	0.01
Total EPS	**2.45**	**2.80**	**2.78**	**2.78**	**2.97**
Guidance	**2.25-2.55**		**EPS up due to + ExGen**		
Consensus	2.39	2.54	2.61	2.81	3.21
Prior UBS estimates	*2.50*	*2.73*	*2.66*	*2.60*	*2.79*
Regulated EPS	*1.27*	*1.34*	*1.40*	*1.48*	*1.57*
Regulated Guidance	*1.10-1.40*	*1.15-1.45*	*1.25-1.55*		

Source: Company Filings, FactSet, and UBS Estimates

Raising up our target: $35/share

Our valuation is based on 2016E utilities sum-of-the-parts analysis. We are increasing our target from $31 to $35 to reflect both the higher regulated P/E multiple as well as our latest MtM power estimates. We continue to back out the negative FCF from the nuclear plants, assuming they will either be saved or closed prospectively. We continue to apply an 8x EV/EBITDA multiple on the generation business and 1-1.5x turn discount to the regulated utilities to reflect a discount on the regulated business given the pending acquisition of PEPCO. We apply a 2x multiple to the former given our belief that the charge is likely to return in due course as a new long-term storage solution is identified, enabling recovery once more.

Figure 120: Updated SOP Valuation for Exelon

All figures in US $ million except per share data		EV/EBITDA & P/E Multiple					Enterprise Value		
	2016 EBITDA	*Low*			*Base*	*High*	*Low*	*Base*	*High*
Generation	2,108	7.0x			8.0x	9.0x	14,758	16,866	18,975
DOE Nuclear Fuel Disposal Fee Uplift	150	1.0x			2.0x	3.0x	150	300	450
Hedge Value	(305)	7.0x			8.0x	9.0x	(2,135)	(2,440)	(2,745)
Other/Equity Investments	229	7.0x			8.0x	9.0x	1,600	1,828	2,057
Retail Margin (Power+Non-Power)	527	4.0x			5.0x	6.0x	2,107	2,633	3,160
Total / Implied	2,708	*6.1x*			*7.1x*	*8.1x*	16,479	19,188	21,896
less ExGen net debt (incl PTC/ITC benefits)		**EBITDA is up ~11% following latest**						(5,509)	
less HoldCo debt		**Power recovery since August**						(1,300)	
add Hedge Value								305	
Adding back the FCF drag from Potential Retirements (Clinton, Byron, Ginna, Quad Cities)	141	7.0x			8.0x	9.0x	985	1,126	1,266
NPV of Equity							10,961	13,810	16,659
Current Number of Shares outstanding							866	866	866
Merchant Generation value per share							***$ 12.66***	***$ 15.95***	***$ 19.25***
Regulated Utilities			**P/E Multiple**					**Equity Value**	
	2016 Net Income	*Low*	*Peer*	*Prem/ Discount*	*Base*	*High*	*Low*	*Base*	*High*
BGE Net Income	198	12.3x	14.8x	-1.5x	13.3x	14.3x	2,432	2,630	2,828
PECO Net Income	417	12.8x	14.8x	-1.0x	13.8x	14.8x	5,341	5,758	6,175
ComEd Net Income	599	12.3x	14.8x	-1.5x	13.3x	14.3x	7,364	7,963	8,561
Total / Implied	*1,214*	*12.5x*			*13.5x*	*14.5x*	*15,137*	*16,351*	17,564
Implied EPS	*1.40*								
Current Number of Shares outstanding							866	866	866
Regulated Utility value per share							***$ 17.49***	***$ 18.89***	***$ 20.29***
Total Equity Value per Share							**30.15**	**34.85**	**39.54**
Potential Accretion on POM Deal	*EPS*	*Low*	*Peer*	*Prem/ Discount*	*Base*	*High*	*Low*	*Base*	*High*
EPS Accretion (2017 UBSe)	$0.15	12.8x	13.8x	0.0x	13.8x	14.8x	***$ 1.97***	***$ 2.13***	***$ 2.28***

Source: Company Filings, FactSet, and UBS Estimates

FirstEnergy Corp. (Sell; $26 PT)

3Q looks down YoY versus consensus expecting flat but improvement in FES MTM and bullish potential PJM reforms could carry the day

We expect FE to report a $0.07 decline YoY and miss versus consensus which is estimating a flat quarter.

FirstEnergy is estimated to report 3Q14 adjusted EPS of **$0.87**, down YoY and notably below consensus ($0.94). The weather will be a negative factor with a ~15% decline in CDDs across the service territory and higher O&M, D&A, etc. also pulling down the comparative results. Taxes and other items help to offset some of the erosion but the addition of portfolio insurance and management opting to reduce risk in the book following the polar vortex will likely further suppress earnings.

We expect that management will reaffirm its FY14 guidance range of **$2.40-$2.60** with 3Q14 results as our full-year earnings estimate is approximately at the midpoint ($2.47). As we elaborate on below, the FES guidance could be revised upward $50Mn with results or EEI in subsequent weeks following the improvement in pricing this Fall.

Figure 121: 3Q14 Earnings Walk

3Q13 EPS	**0.94**
Weather Effect on Utility Sales	(0.05)
Ohio Distribution Rider	0.00
O&M	(0.03)
General Taxes	(0.01)
D&A	(0.02)
Interest Expense	(0.01)
Cost to Serve Contracted Load (Retail item) + Outage Insurance	(0.01)
Taxes	0.03
Net Capacity Benefit/Expense (Retail-item)	0.02
Transmission Expense (Retail-item)	0.01
3Q14E UBSe Adjusted EPS	**0.87**
Consensus	*0.94*
2014 FE EPS Guidance Range	*2.40-2.60*

Source: Company Filings, FactSet, UBS Estimates

Links to our relevant recent research are below:

8/6/14 Where's the Value in Power?

8/5/14 Asking For Help When Times are Tough in Ohio

7/30/14 Competitive Dis-Synergies

In The Interim, PJM Could Go Higher

FE stands to benefit from the latest PJM proposed reforms as would allow it to clear its assets that have not cleared in previous auctions.

In PJM's October 7th white paper on (please see our note '**Ramping Up Compensation, Sooner**') one of the proposals focuses in on compensation in the interim period, a potential reform that could benefit FE more than peers. The new 'Capacity Performance' (CP) product has price and offer caps of $165 and $211/MW-day for 2017/2017 and 2017/2018, respectively.

For winter 2015/16 PJM proposes to procure an additional 10GW of capacity – seemingly beneficial to those assets having not cleared, with FirstEnergy (FE) benefitting in particular in our view, giving assets which didn't clear the auction on

the first go around, another shot. On its 2Q14 call FE disclosed that its 2.5GW Bruce Mansfield Plant did not clear in the 2017/2018 and "only partially cleared" in 2016/2017. We think price caps will likely be triggered, particularly in more constrained zones during those periods (emphasis on PSEG, ATSI, etc.). Notably, we do not see new build resources as truly eligible to participate during this transition, enabling a meaningfully higher compensation value. We believe retailers such as EXC and FE could well face some offsets – but will both still materially benefit.

Ohio Docket Growing Increasing Crowded

FE's application for generator assistance has led to AEP following with a similar filing but the same punchline – asking for an above-market contract.

FE filed its Electric Security Plan in Ohio in early August which if approved by the Public Utilities Commission of Ohio (PUCO) would award the company's merchant business with a PPA-rider for ~3.2GW of generation. We have estimated that the PPA would begin at ~$65/MWh and rise by $2/MWh per year – essentially backing-into a ~$21/MWh uplift on current power and capacity prices. While we have written about the potential for a $50+/MW-Day improvement in the upcoming PJM capacity market, a $50/MW-Day improvement would still imply that the PPA would be $19/MWh above market.

Since its filings AEP has followed the same path with a very similar request. AEP Ohio filed an expanded PPA requesting an initial $2/MWh rider with PUCO for ~2,700MW of its Ohio merchant capacity. While Staff notably rejected the notion of even including a rider for AEP's stake in OVEC under its testimony in the existing ESP docket, we wouldn't be surprised to see the subject revisited by the Commission (even outside of the current case). AEP has asked for the contract to take effect in June 2015.

FE has asked for a decision in April, notably before capacity auction bidding decisions have to be made.

The statutory deadline for FE's decision is May 2015; however, management has requested a decision a month earlier in April so that it can adjust its strategy for the capacity auction, etc. appropriately. The docket is seeing an increasing number of interveners including EPSA (Power trade association), P3 (PJM-specific power trade association), and DYN among other generators. We see this as among the few issues in recent memory where the industry could be poised to see in-fighting on a question of higher compensation for existing generators. We flag efforts by EXC in Illinois (also an intervenor in FE's case) to save its nuclear fleet remain particularly committed to a 'market' solution (renewable, carbon, etc.) rather than bilateral approach taken in OH.

FirstEnergy's testimony and hearings on the proposal are set for December 19th and January 20th, respectively. Settlement negotiations typically take place in this window, and we understand this is indeed the intention on the current filing as well. We caution that Staff is likely to be persistent in rejecting against the contract in its initial testimony

A Look at the 'New Regulated Strategy':

The Long Wait Continues in New Jersey

As the September 30th deadline came for the ALJ in FE's Jersey Central Power & Light (JCP&L) ratecase, the New Jersey Board of Public Utilities (BPU) approved yet another extension to November 13th from September 29th. If you recall from our 2Q14 Earnings Preview, previously we had expected an initial ALJ decision by August 14th with a final decision by September 29th.

NJ BPU approved extending the ALJ's proposed decision to November 13th.

There remains a possibility that the New Jersey BPU could look to have more certainty on issues such as the Consolidated Tax Adjustment and 2012 storm costs before ruling here but investors currently remain in a holding pattern on New Jersey. Please refer to the section on PSEG for further details on the changes at the BPU including notably a new President, Richard Mroz (R). [Docket ER-12111052]

FE $400Mn Rate Case: "Should be Pretty Straight Forward"

In early August FirstEnergy filed for rate cases across its four Pennsylvania regulated utilities and is requesting a $416Mn increase premised on a 10.9% ROE and equity ratio around 50%. These utilities previous rate cases were all decided over seven years ago with the Penn Power case decided in 1988 with the latest delay due to the stay-out provision following the 2010 $4.7Bn Allegheny Energy acquisition. The ROEs previously were 10.1% at Met Ed and Penn Elec. with 10.9% at Penn Power and 11.5% at West Penn. In September we met with Pennsylvania Public Utility Commission (PUC) Chairman **Robert Powelson** who characterized the rate case as "pretty straight forward" and stated that since the case is based primarily on infrastructure spending he does not anticipate significant changes from management's initial request. FE will rely upon the Distribution System Improvement Charge (DSIC) in addition to other riders to receive accelerated recovery. A decision is expected in Pennsylvania by April 2015. Dockets: C-R-2014-2428742 - 2428745

FE's PA rate cases looks lower risk than the pending NJ case.

Figure 122: Summary of FE Pending PA Ratecases

Utility	Rate Increase ($Mn)	Previous Rate Case	ROE	Previous ROE	Equity Ratio
Met Ed	151.9	2007	10.90%	10.10%	50.00%
Penn Elec	119.8	2007	10.90%	10.10%	49.90%
Penn Power	28.5	1988	10.90%	10.90%	50.10%
West Penn Power	115.5	1994	10.90%	11.50%	50.10%
Total	**415.7**		**10.90%**		**50.03%**

Source: SNL Energy

What about the other utilities?

We also are waiting on a decision from the West Virginia Commission on the pending ratecases there (Monongahela Power [Mon Power] and Potomac Edison [PotEd]) where the company is looking for an 11% ROE on 46.5% equity ratio versus SNL's estimate of a 10.1% ROE and 41.6% equity component in 2010. A decision is expected by the end of February and it remains to be seen how the Commission will view FE's request for a material increase in the ROE and equity component. Docket C-14-0702-E-42T

We continue to view the two required cases in New Jersey and West Virginia as the riskiest.

Figure 123: FirstEnergy Utility Information

State	2013 Customers (Thousands)	2013 GDP Growth	2014E Retail Sales %	ROE Range	RRA Ranking
West Virginia	525	3.4%	50%	10.50%	Below Average
Maryland	256	2.3%	33%	11.90%	Below Average
Pennsylvania	2,023	1.9%	36%	10.1%-12.9%	Average
New Jersey	1,098	2.8%	45%	9.75%	Average
Ohio	2,087	1.9%	39%	10.50%	Average

Source: Company Filings and SNL Energy

A more comprehensive discussion of FE's regulatory jurisdictions and the pending rate cases is available in our note '**Competitive Dis-Synergies**'.

FirstEnergy: Pursuing the TrAIL Less Traveled

Requesting to pay dividends from TrAILCo up to the parent

Trans-Allegheny Interstate Line Company (TrAILCo) filed a request with the FERC on October 7th to periodically make dividend payments to its parent FirstEnergy Transmission (FET) from paid-in capital "to maintain a balance capital structure." As of its May 15th filing (Docket ER07-562), TrAILCo had a 59% equity ratio and stated that it will only make dividend payments to FET as long as its equity ratio is greater than 45%; management comments that FERC has not viewed dividends as excessive as long as the equity balance is 30%+ (citing an Entergy Louisiana case and consistent with FERC Form filings). Management has requested a declaratory order by December 8th.

Potential for $400Mn of dividends over time if targeting a 50% equity ratio, before accounting for additional earnings.

As of 2Q14 FERC filings TrAILCo has $853.5Mn of "Other Paid-In Capital" and total equity of $912Mn and total debt of $503Mn for a book capital structure of $1.4Bn, implying a 65% capital structure. Using this as a base, TrAILCo could dividend up to its parent ~$400Mn while still maintaining a 50% equity ratio.

Figure 124: Calculation of TrAILCo Dividend Potential as of 6/30/14

TrAILCo 6/30/14	$Mn	TrAILCo 6/30/14 Est.	$Mn
Other PIC	853.5	Other PIC	853.5
Retained Earnings	58.5	Retained Earnings	58.5
Less: Dividends	-	Less: Dividends	(400.0)
Total Equity	912.0	Total Equity	512.0
Long-Term Debt	451.4	Long-Term Debt	451.4
Note Payable	51.8	Note Payable	51.8
Total Debt	503.2	Total Debt	503.2
Total Cap.	1,415.2	Total Capitalization	1,015.2
Equity Ratio	**64%**	**Equity Ratio**	**50%**
Dividend Assumption	-	Dividend Assumption	(400.0)

Source: Company Filings and UBS Estimates

This request is consistent with management's stated intention of levering up the transmission business and using cash to paydown the revolver borrowings. As of 4/30/14 FE had $750Mn of borrowings on its FET/ATSI/TrAILCo revolver but as of the last update (7/31) there is no revolver balance outstanding and FE has paid down $650Mn over the past three months.

Figure 125: Updated FE Liquidity Analysis

FE Liquidity Analysis 7/31 QoQ - Revolver										
		As of 7/31/14 ($Mn)			*As of 4/30/14 ($Mn)*			*Change*		
Borrowers	Maturity*	Commit.	Available Liquidity	Borrowed	Commit.	Available Liquidity	Borrowed	Commit.	Available Liquidity	Borrowed
FirstEnergy	March 2019	3,500	1,429	2,071	3,500	1,629	1,871	-	(200)	200
FES/AE Supply	March 2019	1,500	1,127	373	1,500	1,031	469	-	96	(96)
FET/ATSI/TrAIL Co	March 2019	1,000	1,000	-	1,000	250	750	-	750	(750)
AGC	Dec. 2013	-	-	-	-	-	-	-	-	-
	Subtotal	6,000	3,556	2,444	6,000	2,910	3,090	-	646	(646)
	Cash	-	107		-	119		-	(12)	
	Total	6,000	3,663	2,444	6,000	3,029	3,090	-	634	(646)
* Note: The maturities were amended to March 2019 from May 2018 previously										

Source: Company Filings and UBS Estimates

Connecting the Dots on Guidance

With management waiting on critical regulatory datapoints (see right), it is unlikely that the company will provide consolidated 2015 guidance with either 3Q14 results or EEI. Despite the pending Ohio request, we still expect management to provide an update on FES, specifically an update on 2015E (open and closed) adjusted EBITDA update as potentially 2016. Below we present out latest mark-to-market reflecting pricing as of the second week of October. FES 2015E guidance could be increased by $50Mn to $950-$1,050Mn and 2016 initial guidance of **$700-800Mn** provided.

Key dates on the horizon:
NJ BPU: November?
WV PSC: February 2015
PA PUC: April 2015
PUCO: April 2015

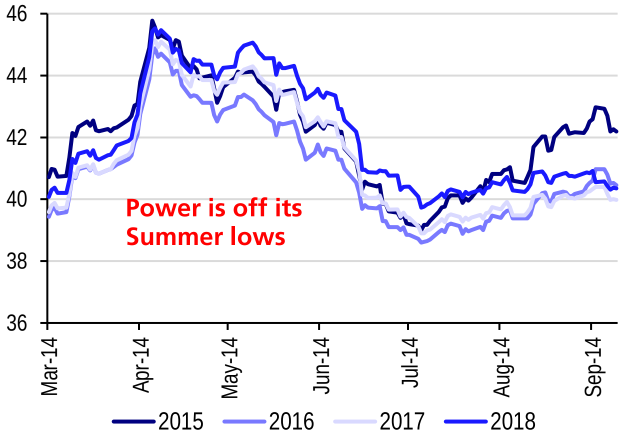
Figure 126: Updated FES EBITDA Estimates

Gross Margin	2012	2013	2014	2015	2016	2017	2018
Open Coal Energy Margins	210	322	396	588	541	571	628
Open Nuclear Energy Margins	921	730	761	840	829	844	876
Hedge Value (From Analyst Day+MtM Since)	373	805	451	(112)	(5)		
Capacity Revenues	405	170	340	892	670	374	385
Marketing Margin (UBSe Retail Margins)	397	259	44	100	90	90	90
Gross Margin (Gen/Retail-Only)	2,307	2,285	1,994	2,308	2,125	1,879	1,979
Other Gross Margin	946	719	883	883	883	883	883
Total Gross Margin	3,253	3,004	2,877	3,192	3,008	2,763	2,862
EBITDA	2012	2013	2014	2015	2016	2017	2018
Open Fossil EBITDA	(21)	(141)	53	727	479	204	231
Open Nuclear EBITDA	238	41.12	169	292	169	188	253
Retail & Hedges & Other EBITDA	1,288	1,329	441	(3)	112	117	117
FES Total	1,505	1,229	664	1,016	761	509	601
Adjusted EBITDA Guidance			615-655	900-1000			

Source: Company Filings and UBS Estimates

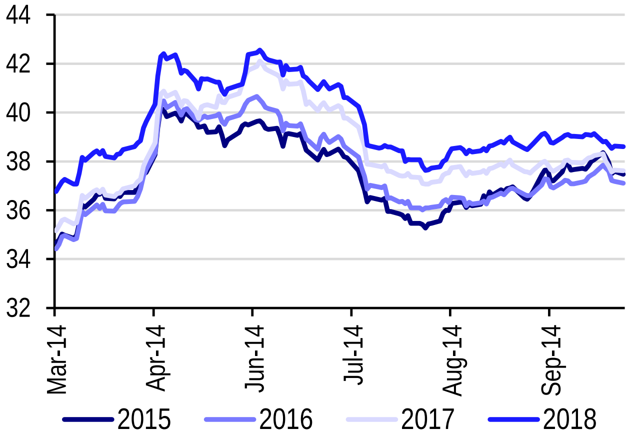
FE's previous Analyst Day was in February 2012 and we would not be surprised if the company ultimately hosts its next Analyst Day in 2H15 once it has updates across these key fronts although no decision has been made.

Figure 127: PJM West ATC Price ($/MWh)



Source: Platts

Figure 128: AD Hub ATC Price ($/MWh)



Source: Platts

Valuation: Maintain Sell Rating and Lift PT $2 on Higher Peer Multiple

We are moving our regulated valuation slightly higher but still see FES as having negative equity value when normalizing capacity payments.

Our valuation remains derived via a 2016E utilities sum-of-the-parts analysis. We are increasing our Price Target $2 to $26 following the regulated utilities group multiple expansion since our previous update; however, still see shares as trading well above their fundamental value when fully netting out the FES and parent obligations. Even with the modest recovery in power as of late, we continue to view FES as having negative equity value utilizing an 8x EV / EBITDA multiple when using capacity price normalization to $100/MW-Day. While

Removing the capacity price normalization from our valuation would be worth ~$4/sh, turning from a negative $2/sh valuation (excluded from our valuation as we assume this is a non-recourse entity) to a positive $2/sh. While we do not dent the potential upside from the proposed PJM reforms, especially the interim auctions for FE, but we view other IPPs and generators as more favorably exposed than FE which currently has a negative valuation based on our calculations.

Figure 129: Updated FE Valuation

Sum of the Parts Analysis - Combined Hedged and Open Analysis - UBSe - Using both EV/EBITDA and P/E

Merchant Generation	EBITDA/Net Income: 2016 EBITDA	EV/EBITDA & P/E Multiple: Low	Base	High	Enterprise Value: Low	Base	High
Open Fossil Energy EBITDA	479	7.0x	8.0x	9.0x	$3,356	$3,836	$4,315
Open Nuclear Energy EBITDA	169	7.0x	8.0x	9.0x	$1,184	$1,353	$1,523
Capacity Price Normalization @ $100/MW-day	(195)	7.0x	8.0x	9.0x	($1,362)	($1,556)	($1,751)
Marketing (Retail + Hedges)	112	4.0x	5.0x	6.0x	$449	$561	$673
Total / Implied	566	6.4x	7.4x	8.4x	$3,628	$4,194	$4,761
Less: FES/AES Net Debt - Excluding Leasebacks (2015 YE)						($4,825)	
Net of FES						($631) (B)	
Add: Signal Peak Equity Value (PRB Coal Mine Stake)						$400 (B)	
Add: Capacity Payment Normalization for 2015/16 auction in ATSI						$195 (B)	
Less: Recourse FES Obligations (Sale Leaseback)						($971) (A)	
Less: Other Parent Sale Leasebacks						($129) (A)	
Less: Parent Notes (4/30)						($4,231) (A)	
Less: Parent ST Borrowings						($1,871)	
Add Back: FirstEnergy Transmission Borrowings						$1,000	
Allocate: 100% of Parent Borrowings to Regulated Utilities						$871	
(A) FES Equity (Net of Parent Debt)					($6,564)	($5,331)	($5,331)
Number of Shares Outstanding - 2016 (Mn)					424	424	424
FES Open Equity Drag per Share (Net of Parent Debt)					($15.49)	($12.58)	($12.58)

Room for Downside at FES:

Assuming FES is non-recourse, we excluding $1Bn of equity drag ~$2/sh

Assuming Parent revolver is used to finance regulated operations ~$2/sh

(A): Recourse Obligations of First Energy Solutions (Sale Leaseback and Parent Notes)

(B): FES Valuation and Non-Recourse Obligations

Regulated Utilities	2016 Net Income	P/E Multiple: Low	Peers	Premium/ Discount	Base	High	Equity Value: Low	Base	High
Core Utilities									
Energy Delivery (FE and AYE Utilities)	886	12.5x	14.5x	-1.0x	13.5x	14.5x	$11,076	$11,962	$12,848
Transmission (ATSI, TRAIL)	327	14.5x	14.5x	1.0x	15.5x	16.5x	$4,743	$5,071	$5,398
Total EPS	*2.86*								
Parent Costs									
Net HoldCo/Parent Expenses (SG&A, etc)	(101)	13.5x	14.5x	0.0x	14.5x	15.5x	($1,369)	($1,470)	($1,571)
Add Back: Parent Interest Expense	107	13.5x	14.5x	0.0x	14.5x	15.5x	$1,445	$1,552	$1,659
Net Parent EPS (SG&A ex-Interest)	*0.01*								
Dis-Synergies	*(59)*	13.0x	14.5x	-0.5x	14.0x	15.0x	($768)	($827)	($885)
Total / Implied Utilities	1,160	16.4x			14.0x	18.9x	$15,895	$16,287	$18,333
Total Regulated EPS	*2.74*								
Number of Shares Outstanding - 2016 (Mn)							424	424	424
Regulated Utilities & Transmission Equity value per share							$37.50	$38.42	$43.25
Less: Recourse FES Obligations (Sale Leaseback)								($971)	
Less: Other Parent Sale Leasebacks								($129)	
Less: Parent Notes (4/30)								($4,231)	
Parent/FES Drag per Share								($12.58)	
FirstEnergy Combined (Regulated & FES) Equity Value							$22.01	$25.85	$30.67

Utility-Only Valuation is based on P/E for utilities less the parent/FES drag

Source: Company Filings, FactSet, and UBS Estimates

ITC Holdings Corp (Buy; $39 PT)

Standard quarter with possibility of slight '14 guidance bump; clarity on REIT remains elusive

Another steady quarter for ITC with few surprises anticipated on the call.

ITC is estimated to report 3Q14 EPS of **$0.45**, up from $0.42 in 3Q13 and once again largely in-line with consensus. The call will likely focus on the usual topics of FERC ROE/possibility of incentives, REIT opportunities, and Order 1000 but given the absence of clarity on almost all fronts, we do not anticipate any material new disclosures. In the past two years management has updated its guidance in October and we would not be surprised to see the same this year with a slight tightening of the bottom-end of the range perhaps by ~$0.02. FY15 guidance is expected to be provided with fourth quarter earnings.

Figure 130: 3Q14 Earnings Walk

ITC EPS	2011A	2012A	2013A	3Q14E	2014E	2015E	2016E	2017E	2018E
ITC Transmission	0.54	0.57	0.68		0.78	0.75	0.78	0.80	0.87
METC	0.39	0.46	0.52		0.57	0.58	0.64	0.69	0.77
ITC Midwest	0.49	0.59	0.71		0.78	0.87	1.12	1.41	1.60
ITC Great Plains	0.04	0.09	0.15		0.22	0.25	0.27	0.29	0.30
Parent Drag	(0.36)	(0.32)	(0.41)		(0.47)	(0.50)	(0.56)	(0.65)	(0.75)
ITC Consolidated	1.10	1.38	1.64	0.45	1.87	1.94	2.24	2.54	2.79
YoY Growth		*25%*			*14%*	*4%*	*15%*	*13%*	*10%*
Prior UBSe			*1.62*		*1.87*	*1.94*	*2.24*	*2.54*	*2.79*
Guidance					*$1.83 - 1.90*				
Consensus			*1.63*	*0.47*	*1.87*	*2.07*	*2.19*	*2.30*	*2.88*
Financial ROE	14.4%	16.2%	17.1%	-72.9%	18.2%	18.5%	19.9%	20.5%	20.6%
ITC Guidance					2011-2016:	15-17%	2013-2018:		11-13%
UBSe *(Adjusted down for ROE)*						15.3%			11.2%

Source: Company Filings, FactSet, UBS Estimates

Links to our relevant recent research are below:

9/5/14 Set to Raise Expectations
8/19/14 Breaking Down the New FERC Methodology
8/7/14 Poised for New CFO Leadership

Once again, all about REITs and ROEs

ITC still continually evaluating the potential of a REIT but do not want to sacrifice long-term flexibility for a short-term valuation uplift.

We met with management last month and the conversation was dominated once again by considerations that factor into whether ITC could (and would) convert to a REIT. We increased our probability of a REIT to 20% with our 2Q14 note following the comments, or lack thereof, on the most recent earnings call but management shed additional light onto the topic. The company emphasized that there are both positives and negatives with opting for a new corporate structure with the 75% asset test being towards the top of the list as it limits diversification opportunities. Two other areas of uncertainty that the company said they would have to gain comfort with include confidence on the continued health of the equity markets (given the need to continually issue equity to finance the REITs growth) and certainty surrounding tax reforms. With the latest rhetoric around potential tax reform due to tax inversion M&A this Summer and into the early Fall,

management appeared more cautious in particular on this front. Wisconsin Energy specifically addressed a similar question about REITs/YieldCos at a recent conference as well but expressed skepticism when CEO Gale Klappa stated that the entities "may not create permanent shareholder value." Regardless, WEC management would likely not truly consider such a corporate structure change ahead of the closing of its pending Integrys Energy Group (TEG) acquisition which is still set to close in 2H15.

Could ITC form a true YieldCo where it spins-off existing, stable transmission assets while leaving the growth story intact?

Having said this, we increasingly believe that the possibility exists for ITC to essentially form a REIT 'YieldCo' and spinoff assets into the new vehicle as they reach maturity. The benefit here is that the company would maintain its flexibility to pursue growth while also getting a higher valuation of the stable components of the business. Throwing cold water on the story in the short-term was the logical comment that it is unlikely to expect any radical changes before MISO ROE clarity. FERC could act on the MISO sooner rather than later and based on our recent mark-to-market, we see a ~100bp higher FERC 75th percentile at 11.56% based upon a 6.74-13.16% zone of reasonableness (details below).

We discuss Kansas Corporation Commission's Section 206 transmission formula rate complaint against Westar Energy later in the preview but we do not believe that that ITC Great Plains (Kansas and Oklahoma subsidiary) faces the same challenge as the background issues appear to be more Westar specific.

Do not expect significant discussion on the earnings call

In light of the uncertainty around MISO and management's discussion to hold its playbook close-to-the-vest, we would not anticipate the company shedding too much additional light on the REIT or plans to file for ROE incentives at this time, although an earlier request would have a positive refund impact. We still believe a key point of misunderstanding among investors is management's ability to file for new incentives (up to 1.5%) at several of its utilities (ITC Midwest and METC).

What did we learn about REITs from our visit to Oncor management?

While the Texas story is more nuanced with the PUCT (Texas Commission) and local ratepayer dynamics versus ITC's federal regulated strategy, we believe that ITC would not want to be the REIT test case and management's preference is to be a fast follower here rather than a pioneer.

What is obfuscating the REIT story in Texas?

While on paper, we continue to question the ability to do a REIT from an IRS perspective is likely relatively straight forward (structured as an Operating Company and Property Company), the ability for any parent company to retain the benefits is less clear following a look at recent legal datapoints in Texas. The underlying question in both cases below relates to whether the tax status of the parent company has an impact on the utilities' ability to recover income taxes from ratepayers.

- **Centerpoint's pending stranded cost case:** There appears to be some uncertainty as to whether the pending Supreme Court case on the treatment of income taxes for its pending refund back to the company. While a decision on this case appears protracted, this could yet act as a deciding factor in how the PUCT would be required to treat holding company effective tax rates. Centerpoint has continued to state it does not believe it could execute on a REIT structure for its utility in the state.

- **CTSA [Consolidated Tax Savings Adjustment] in 2008 Oncor rate case:** Among the other chief cases discussed in evaluating whether there is legal latitude for the PUCT (Texas Commission) to allow the company to retain the income tax benefits at Oncor, irrespective of the tax status at the parent. While the decision not to pierce the corporate veil had been decided in the affirmative at the PUCT – and in a subsequent appeal – the latest appeal of the decision has sided against the company. While it is yet out upon a further appeal (potentially going to the State Supreme Court), this remains among the biggest question marks.

What is the latest with the New England FERC ROE challenge? Much ado about nothing

The latest battleground for New England ROEs relates to the macro component of the two-step ROE with the New England Transmission Owners (NETO) challenging the GDP component. Specifically the NETO believes that (1) the growth rate is too low at 4.39% and (2) the weighting for GDP at one-third is too high, both of which they argue applies downward pressure on the ROE. The long-term (2017-2040+) GDP forecast comes from a third party consultant, the EIA, and Social Security Administration (SSA); in our latest mark-to-market exercise we consulted the latest available information from the EIA and SSA noting insignificant changes. For example, if the GDP growth assumption were increased by 10bp, the FERC 75th percentile would increase to 10.60% from 10.57%, a largely immaterial change. A 50bp move would drive a 10.74% ROE; however, such a material upward revision appears unlikely given the data presented.

Figure 1: ROE Analysis Summary

ROE Analysis Summary	*Low*	*Midpoint*	*High*	*FERC 75th %*	*"True" 75th %*
Zone of Reasonableness (Original)	7.03	9.39	11.74	10.57	9.77
Zone of Reasonableness (1/4 GDP Weight)	6.97	9.51	12.05	10.79	9.84
Zone of Reasonableness (UBSe MTM)	6.74	9.95	13.16	11.56	9.48
Zone of Reasonableness (Adj. MTM)	6.74	9.24	11.75	10.49	9.48

Source: Company Filings, Yahoo! Finance, and UBS Estimates

While this argument may have more weight, it is difficult to quantify the appropriate weights necessary for such a hypothetical analysis. If the weighting is shifted to be (3/4) for IBES Growth Rate [versus (2/3)] and (1/4) for GDP Growth Rate [versus (1/3)], the outcome would be a 22bp increase in the FERC ROE to 10.79%. While this is a more material increase than a minor tweaking of the GDP expectation, given the seemingly arbitrary split between IBES and GDP weighting in the first place, we would expect NETO struggling to provide a detailed analysis to justify such a change in methodology, especially at the eleventh hour.

For further details of the FERC methodology and our mark-to-market, please refer to our note **'Breaking Down the New FERC ROE Methodology'**; please ask us for a working Excel model version.

What about FERC 1000? Cuts both ways

Independent orientation appears to be yielding early benefits in California but only time will tell if that translates into opportunities versus incumbents.

Management continues to view competitive bidding as a positive catalyst that opens the door for the company to expand its footprint. ITC has specifically not looked to gain incumbent advantageous in its 'home territories' in order to preserve the playing field in new regions. While the company has shied away from California in the past, it actively is receiving requests 'all the time' from developers in the state who value ITC's independent nature and believe it gives them an advantage in competitive solicitations. In its 'Tier One' alone (SPP and MISO North

& South) management sees $9.5-11.0Bn of opportunities with MISO South being an area for opportunity as the company leverages the intel it gains from the attempted Entergy transaction. Speaking at an Energy Summit conference in late September, Thomas Wrenbeck ITC Director of Regulatory Strategy, commented that he believes further FERC rules will need to be layered on top of Order 1000 as the process is fleshed out further – the process with Artificial Island is proving this point to be true. We remind investors that selection criteria appear to be quite different across RTOs, with PJM requesting project 'solutions' whereas MISO is asking for cost effective designs to address more specific projects.

ITC Breaking New (Merchant) Ground

First real merchant project shows willingness to expand footprint beyond MISO

ITC announced the development of the Lake Erie CleanPower Connector merchant transmission project after purchasing the development rights for the 1,000MW PJM project. ITC has subsequently renamed the project as ITC Lake Erie Connector and the underground line would span ~70 miles underground between Pennsylvania and Ontario. The company has filed an interconnection request and received FERC authorization on September 26th for negotiated rate authority on the project.

As a reminder, mgmt. has haircut its capex forecast to ~20% of gross, suggesting it remains quite conservative

Project could well capitalize on ATSI focus in PJM – and resembles another similar proposal by PJM

This is a notable move for ITC as previously it has relied upon FERC cost-recovery transmission projects with relatively low risk whereas the company bears significantly more risk in these merchant projects. With the necessary approvals in hand, management likely began the open solicitation process shortly after FERC approval to secure counterparties for the line. Upon project completion ITC will cede operational control to PJM and the firm stated in the filing that it may pursue additional PJM transmission opportunities in the future. While such a project is less certain than its core cost-recovery capital spending, it shows management is willing to expand beyond its traditional footprint. The counterpoint is that this does elevate the company's risk profile and it remains to be seen how the market will treat the company (which currently trades at a ~1x P/E premium) if it materially enters the merchant transmission business. Management characterizes the project as a test case (Docket ER14-2640).

Consensus continues to decline

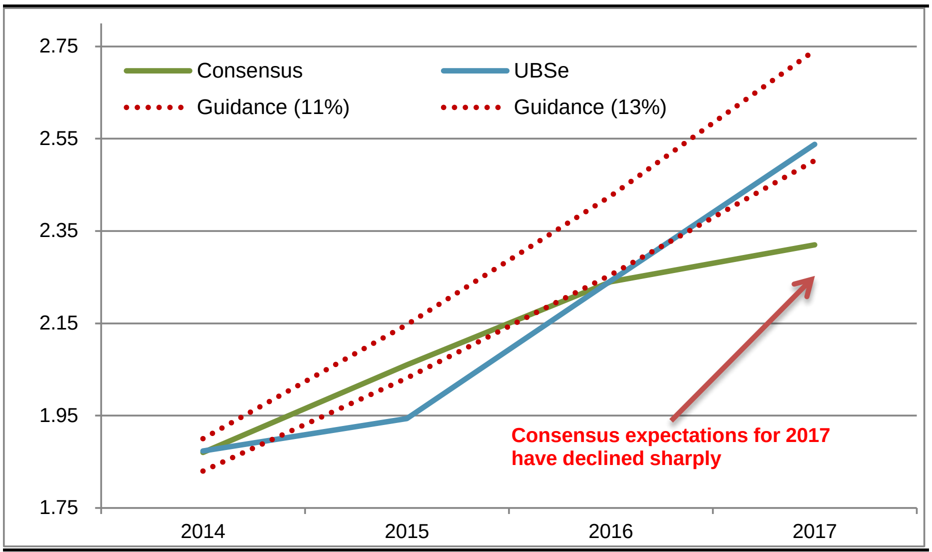
Below we present changes in 2014 to ITC consensus EPS estimates for 2014-2017 which contracted sharply in June following the FERC New England ROE decision but expectations continue to decline. 2016 consensus declined another nickel to $2.19 in September/October, now implying that the Street does not see ITC meeting even the low-end of its 11-13% guidance range.

Figure 131: Comparison of ITC Consensus and UBS EPS Estimates

	2014 Consensus				2015 Consensus				2016 Consensus				2017 Consensus				'14-'17 CAGR
	Mean	*Low*	*High*	*Std Dev*	*Mean*	*Low*	*High*	*Std Dev*	*Mean*	*Low*	*High*	*Std Dev*	*Mean*	*Low*	*High*	*Std Dev*	
January-14	1.86	1.85	1.89	0.01	2.11	2.05	2.15	0.03	2.31	2.20	2.40	0.10	N/A	N/A	N/A	N/A	N/A
February-14	1.86	1.85	1.89	0.02	2.12	2.10	2.15	0.02	2.32	2.20	2.40	0.09	2.49	2.40	2.58	0.13	10.2%
March-14	1.86	1.85	1.88	0.01	2.11	2.10	2.15	0.02	2.32	2.20	2.38	0.08	2.49	2.40	2.58	0.13	10.2%
April-14	1.87	1.84	1.90	0.02	2.12	2.06	2.20	0.04	2.33	2.19	2.45	0.08	2.64	2.58	2.73	0.08	12.2%
May-14	1.88	1.84	1.90	0.02	2.12	2.09	2.20	0.03	2.35	2.27	2.45	0.06	2.66	2.60	2.73	0.09	12.3%
June-14	1.87	1.83	1.90	0.02	2.07	1.82	2.20	0.10	2.26	2.02	2.39	0.11	2.32	1.82	2.60	0.43	7.5%
July-14	1.87	1.83	1.90	0.02	2.07	1.82	2.20	0.10	2.23	2.02	2.30	0.09	2.39	1.82	2.60	0.38	8.5%
August-14	1.87	1.84	1.90	0.02	2.07	1.82	2.20	0.10	2.23	2.02	2.30	0.09	2.39	1.82	2.60	0.38	8.5%
September-14	1.87	1.84	1.90	0.02	2.06	1.82	2.15	0.10	2.24	2.02	2.45	0.11	2.32	1.82	2.60	0.43	7.5%
October-14	1.87	1.84	1.90	0.02	2.07	1.82	2.15	0.10	2.19	1.95	2.45	0.14	2.30	1.82	2.60	0.35	7.1%
YoY Growth (%)	14.7%				10.7%				5.8%				5.0%				
UBSe	1.87				1.94				2.24				2.54				10.6%
Delta (%)	0.2%				-6.1%				2.4%				10.3%				49%
Guidance (Low)	1.83				2.03				2.25				2.50				11%
Guidance (High)	1.90				2.15				2.43				2.74				13%

Source: Company Filings, FactSet, UBS Estimates

Figure 132: Comparison of ITC Consensus and UBS EPS Estimates



Source: Company Filings, FactSet, UBS Estimates

Off of a 2014 base we calculate an ~11% 2014-2017 EPS CAGR with consensus declining to a 7% CAGR lately, versus as high as 12%+ earlier this year.

We continue to approach ITC from dual angles with our mini-model arriving at immaterial variances with our formal model. As a reminder, ITC is disproportionately exposed to rising interest rates with ~30% of its capitalization being parent debt without rate recovery of interest rates; however, much of the debt could be refinanced at lower rates.

Figure 133: ITC Mini-Model vs Formal Model – EPS Converges via both methods

ITC Mini Model - Co Projected Year End Ratebase	2013	2014	2015	2016	2017	2018
ITC Transmission	1,310	1,441	1,550	1,536	1,501	1,470
METC	1,050	1,170	1,178	1,219	1,225	1,228
ITC Midwest	1,545	1,780	1,910	2,321	2,788	2,986
Development - ITC Great Plains	370	458	455	476	462	446
Development	-	-	-	-	63	233
CWIP	249	218	515	737	944	1,238
Total	4,524	5,067	5,608	6,289	6,983	7,601
ROE		12.75%	11.76%	11.76%	11.76%	11.76%
Equity Ratio		60.0%	60.0%	60.0%	60.0%	60.0%
Subsidiary Earnings		367	377	420	468	515
Less: Parent Drag						
Parent HoldCo Outstanding		2,133	2,171	2,366	2,433	2,697
Parent Interest Expense		(95)	(100)	(112)	(129)	(149)
Implied Interest Expense Rate		*4.5%*	*4.6%*	*4.7%*	*5.3%*	*5.5%*
Parent SG&A		(25)	(26)	(27)	(28)	(33)
Tax Savings		45	47	52	59	68
ITC Consolidated Earnings per Mini-Model		292	298	333	371	401
ITC Consolidated Earnings per Formal Model		290	296	335	372	402
Delta (Average ~$0Mn)		1	2	(2)	(2)	(1)
Mini-Model Parent Drag per Share		0.61	0.65	0.75	0.88	1.03
ITC Consolidated EPS per Mini-Model		1.88	1.96	2.23	2.53	2.79
ITC Consolidated EPS per Formal Model		1.87	1.94	2.24	2.54	2.79

Source: Company Filings and UBS Estimates

Leeway to tighten 2014 guidance range

ITC confirmed its 2014 guidance of $1.83-$1.90 on its last call and we still believe that there is the possibility of an increase with 3Q14 results with even our lower 2014 estimate still above the midpoint. While the ROE decision may impact ITC's ability to increase FY14 guidance, we expect that management built in sufficient cushion to avoid a decrease. In every fiscal year from 2008-2012 management has increased its guidance range (in 2013 guidance was revised in October with the low-end increasing and high-end decreasing).

Figure 134: ITC Historical EPS Guidance Changes

ITC - EPS Guidance History		**Guidance Range**		
Date Issued	*Fiscal Period*	*Low*	*High*	*Change*
Oct-2013	FY2013	1.61	1.64	Mixed
Oct-2012	FY2012	1.37	1.38	Increase
Aug-2012	FY2012	1.32	1.35	Increase
Jul-2011	FY2011	1.08	1.12	Increase
Oct-2010	FY2010	0.92	0.93	Increase
Feb-2010	FY2010	0.87	0.90	Increase
Oct-2009	FY2009	0.82	0.84	Increase
Nov-2008	FY2008	0.70	0.71	Increase
Aug-2008	FY2008	0.67	0.68	Increase
Mar-2007	FY2007	0.50	0.53	Decrease

Source: FactSet

NextEra Energy (Buy; $102 PT)

Dime miss on poor wind; expect new presentation of NEP metrics. A quieter 2H14 before '15 updates.

Raising 2015-2017 estimates for a stronger commodity deck but our PT comes down a $1 for a slightly lower average peer utility 2016E P/E multiple.

We expect NEE to report **$1.48** vs consensus $1.57 and last year's 3Q $1.43. Poor wind conditions across its fleet hurt an additional nickel vs last year's also poor conditions (only 92% of normal in 3Q13). A return to normal weather from last year (-3% vs norm CDD) helps a penny while higher GBRA rates for Riviera helps another $0.02. Sales growth is largely offset by -$0.04 from the reversal of depreciation reserves in 2H14, with the reserve expected to be built back up to $245M at yearend from a low of $114M on June 30. At Energy Resources, we expect a +$0.04 improvement from growth in contracted renewables (offset by the 20% minority interest in NEP). We also expect management to initiate additional NEP reporting metrics, including EBITDA and cash flow. Customer supply and trading added +$0.07yoy in 2Q, primarily reflecting structured transactions, and we assume a repeat performance in 3Q. Corporate G&A, interest, and dilution reduce EPS by -$0.06.

Figure 135: NEE 3Q Walk

3Q14 Earnings Walk		EPS
3Q13 Adjusted EPS		
FPL	$	0.99
Energy Resources		0.45
Corp & Other		(0.01)
Total 2Q13 Adj. EPS	**$**	**1.43**
FPL		
Return to Normal Weather (-3% vs norm in 3Q13		0.01
Weather in 2Q14		-
Canaveral (In-Service in April 23, 2013)		-
Riviera (In-Service April 10, 2014)		0.02
Sales Growth		0.04
Depreciation Reserve Reversal		(0.04)
Usage		0.01
Energy Resources		
Continued poor wind (vs 92% in 3Q13)		(0.05)
Asset sales		-
Existing Assets (refueling outages)		-
Net Investment Growth & NEP min interest (20%		0.04
Gas Infrastructure		0.01
Customer Supply & Trading		0.07
Improved Sparks		-
Corp G&A and Other		(0.04)
O&M: Cost Momentum		-
Dilution		(0.02)
Net Income		**0.05**
3Q14	**$**	**1.48**
Consensus		*$1.57*
2014 Guidance		*5.15-5.35*

Source: Company filings, UBS Estimates, FactSet

LT guidance update possible by yearend, but not likely on 3Q call

For 2014, we don't expect any change on the 3Q call to FY guidance of $5.15-$5.35 (vs UBSe $5.25 and consensus $5.31) with TTM now at $5.23 based on our 3Q estimate. Essentially, a strong 1H14 has been offset by about -$0.15 of 1x charges for the NEP launch. NEE's 2016 guidance of $5.50-$6.00 (vs UBSe $6.41 and consensus $6.06) remains unchanged despite a strong 1H, reflecting the company's 5%-7% CAGR off a 2012 base. We continue to see a revision to the 2016 EPS guidance as a visible positive; however, we now anticipate an update in early 2015 versus potentially as early as 4Q14. By early next year NextEra will have certainty on the (1) Florida gubernatorial election, (2) potential PTC extension (mgmt. believes still better than 50% chance of extension with other outstanding tax items), and (3) a Florida Public Service Commission decision on ratebasing of gas assets which could potentially be worth a few hundred million per year in spending.

We have tweaked our estimates below to reflect weather YTD, our estimate of O&M cuts, and our latest stronger commodity outlook.

Figure 136: NEE Estimates, 2013A-2017E

EPS - Segments	2013A	2014E	2015E	2016E	2017E
FP&L	3.16	3.13	3.35	3.53	3.81
NEER	1.83	2.12	2.54	2.74	3.03
Corporate & Other	(0.02)	0.01	0.07	0.14	0.16
Total UBSe	4.97	5.25	5.96	6.41	7.00
UBSe (Prior)	4.97	5.38	5.94	6.38	6.94
Consensus		5.31	5.67	6.06	6.43
Company Guidance		5.15-5.35	5.30-5.60	5.50-6.00	

Source: Company filings, UBS Estimates, FactSet

So what does a Crist election mean for NextEra?

Despite pervasive Street concerns over the subject, we emphasize this is most likely to take the form of a slow-down in capital spend (aside the ratebase proposal) as the company seeks to moderate inflation trends on consumers. Given its rate stayout through 2016, we see more limited political influence at least initially.

We also see timing of any Florida regulatory actions as key, before year end, and without influence of the new election dynamic. Specifically, we're focused on its gas ratebase proposal, which had always been anticipated to be approved before year end anyway. Broadly, we're surprised NEE has been the most negatively affected by election sentiment in the group, with our perceptions of both DUK and TE having been spared despite potentially greater regulatory risk.

Reducing PT $6 to $102 on YieldCo peer weakness; Reiterate Buy rating

Our valuation remains based on a utilities sum-of-the-parts methodology where we ascribe value between Energy Resources (~40%) and FP&L (~60%). We continue to value NEER at 9x for the traditional generation, and to apply a separate development pipeline value to the parent for known projects ($2/sh), seeing a distinct value proposition in the added value of a continued opportunity for YieldCo growth.

We continue to apply a 7x multiple (1x premium that adds $1/sh) for the Gas Infrastructure business to reflect the potential for growth in gas reservoir ratebase (ahead of any formal timetable for utility acquisition/scale). At FP&L, we apply a 1x premium valuation to the regulated business at a 16x multiple of 2016E. FP&L is

among the fastest growing utilities (up 1.2% in 2013 YoY largely due continued positive customer migration) which also carries one of the lowest O&M profiles, which is set to decline substantially when Project Momentum begins yielding substantial benefits.

Figure 137: NEE Sum of the Parts Valuation, 2016E

	2016e Adj. EBITDA	EV/EBITDA & P/E Multiple			Enterprise Value		
Energy Resources		**Low**	**Base**	**High**	**Low**	**Base**	**High**
Traditional Generation	917	8.0x	9.0x	10.0x	7,338	8,255	9,172
Wind (Total)	1,225	11.0x	12.0x	13.0x	13,476	14,701	15,926
Hedges (Texas 'Merchant' Wind)	(79)	11.0x	12.0x	13.0x	(873)	(953)	(1,032)
Tax Credits (PTC)	1,180	7.0x	8.0x	9.0x	8,257	9,437	10,617
Less NEP Initial Wind Assets	*(165)*	*11.0x*	*12.0x*	*13.0x*	*(1,818)*	*(1,984)*	*(2,149)*
Solar (Total), excl ITC	339	11.0x	12.0x	13.0x	3,732	4,071	4,410
Less NEP Initial Solar Assets	*(88)*	*11.0x*	*12.0x*	*13.0x*	*(963)*	*(1,050)*	*(1,138)*
Gas Infrastructure	357	6.0x	7.0x	8.0x	2,141	2,498	2,855
Trading & Retail	134	4.0x	5.0x	6.0x	537	672	806
Total / Implied (ex-ITC)	***3,820***	***8.3x***	***9.3x***	***10.3x***	***31,828***	***35,648***	***39,468***
Add: Silver State Solar NPV						**583**	*$1.25*
Add: NPV Sabal Trail & SE Connection						**830**	*$1.78*
Add: NPV of Remaining Solar and Wind Project Pipeline						**1,086**	*$2.32*
Add: NPV of Texas Hedge						**305**	*$0.65*
Less: Total NextEra Debt						(33,042)	
Netting FP&L-associated debt						9,564	
Netting NextEra Transmission-associated debt						416	
Netting Pipeline debt						-	
Netting NEP Debt						*1,655*	
Net NEE Resources Debt						**(21,407)**	
NextEra Energy Resources					**11,251**	**17,046**	**18,892**
Shares Outstanding (2016e)					467	467	467
NextEra Energy Resources Value per Share					**$24.07**	**$36.47**	**$40.41**

	2016e NI	P/E Multiple							
		Low	Peer	Prem/ Discount	Base Multiple	High			
Florida Power & Light	1,652	15.1x	15.1x	1.0x	16.1x	17.1x	24,942	26,594	28,246
NextEra Transmision	34	16.1x	15.1x	2.0x	17.1x	18.1x	554	588	623
Total Utility	***1,686***	***15.1x***			***16.1x***	***17.1x***	***25,496***	***27,183***	***28,869***
Shares Outstanding (2016e)							467	467	467
NextEra Utilities Value per Share							**$54.54**	**$58.15**	**$61.76**
Value of the NEP GP per Share (IDRs)							$0.61	$1.61	$2.61
NEP Price Target								$34.00	
Value of NEP LP per NEE Share based on NEP Price Target							$5.42	$ 5.42	$5.42
NEP Value per Share							**$11.45**	**$7.03**	**$13.45**
Total Equity Value per Share							**$90.06**	**$101.64**	**$115.62**

Source: Company filings, UBS Estimates, FactSet

What's the right growth rate for NEP? We think an upward revision is likely

We believe management is increasingly biased to raise its structural growth up from its committed 12-15% at NextEra Partners (NEP), up to a range that represents its 'best in class' opportunity set. While management appears keen to keep an eye towards the longevity of its advantageous cost of capital and growth trajectory, it does appear poised to ratchet expectations modestly.

While unclear exactly what a 'best in class' (our words) growth rate would be, we estimate it is somewhere close to NYLD's disclosed 15-18% growth rate, with a biased towards the upper end. While management has complete latitude to engineer NEP drop-downs to its liking, the latest organic outlook for both renewables and midstream would suggest it is indeed possible to have such an acceleration (particularly amidst the meaningful backlog of potential drop downs).

Accelerating drops through 'structured' tax equity deals

Among the most promising developments of late is NextEra's confidence in structuring novel tax equity deals on new wind projects, which would effectively enable for a constant distribution off the project entity through the life of a wind PPA, despite the upfront ten-year tax equity structures put in place on many new deals. Typically these tax equity structures effectively 'grab' all cash flows off new assets during the 10-year life of the Production Tax Credits (PTCs), leaving just the last ten-year period eligible to be dropped into the structure. NEE's proposed structure would allow for a relatively consistent 20-year payout from the structure, effectively allowing NEE to drop down even its newly developed assets into the YieldCo structure. We see the ability to accelerate the drop-down of newly constructed assets as enabling the depreciation benefits to deem cash flows as a 'return of capital'.

Structuring 'tranched' drop-drops the next evolution in YieldCo's?

While not necessarily attributable to NextEra directly, we see the direction of the latest tax equity deal, and potential structuring of a 'note' to effectively pay out cash flows from its Point Beach nuclear unit as indicative of the trend in the YieldCo industry towards financially optimizing 'non-qualifying' assets into YieldCo eligible drops. Diversification across the sector will inevitably continue to push the conventional notion of what is an eligible drop down.

Carbon 111 (d): the biggest driver of long-term renewables growth

Locking in the RPS

We agree with management's view of long-term renewable growth as increasingly driven by carbon 111(d) mandates, with RPS standards likely 'cemented' by final rules. Moreover, many companies will opt to lean heavy on renewables in lieu of EPA's proposed 'building blocks' to achieve targeted reductions (such as excessive levels of coal to gas switching, etc.).

Handling the regulatory relationship in Florida

Utilities are likely hoping that Governor Scott's record on the economy wins out with voters…

As we discussed in **our previous note** following the Democratic primary, a victory by Democrat Crist over incumbent Governor Scott (R) will be perceived negatively for NextEra's Florida Power & Light (FP&L) and TECO's local utilities given previous interactions with the regulated entities. It does not appear to be a secret that the business community is more supportive of Scott but the potential impact of Crist winning is an unknown.

…which will be key for NextEra's next rate case expected in 2016.

Gubernatorial certainty will be key as we look beyond 2016 where management could revise its 5-7% EPS CAGR from 2012-2016 as we assume that FP&L will file a rate case in 2016 (FP&L remains in a rate stay out through 2016). NEE is currently weighing a decision on whether to file a rate case in late 2015/early 2016 for Jan 2017 implementation. In the event of a Crist win, the company may attempt to avoid a filing with cuts to both capital and operating spending in an effort to preserve ROEs (albeit at a slower investment and earnings growth rate) through the duration of his term.

The company does not anticipate its next large generation need until the 2019/2020 timeframe so absent impacts from depreciation studies or utility scale solar, we would not expect significant rate inflation and pushback from regulators.

Risk around Florida PSC appointments declining

With Commissioners Balbis' and Brown's terms expiring at the end of this year and the remaining three Commissioners having terms extending through 2016-2018, Governor Scott's nomination process is currently underway, with 16 candidates recently interviewed for the two opening spots. Our impression is that none of the 16 candidates would be objectionable to the state's utilities. This is important in that should Crist win the election, he may reject Scott's final picks, but may only replace them with the other candidates already approved by the Florida Public Service Commission Nominating Council unless he receives legislative approval for a new nominating process – unlikely to be given by a still deeply Republican legislature that is largely antipathetic to Crist's recent "conversion" to the Democratic party in December 2012. In any event, we believe that a silver lining of a Crist administration could come in the form of a stronger emphasis on (ratebase-eligible) solar initiatives that have been sidelined on economic concerns by Scott. Exposed companies include TE, NEE, and DUK.

Signs of a nuclear renaissance?

Serious Southern nuclear discussions could be kicked off in the next few years as sixty year license expirations loom.

Southern Company spent much of their **2Q14 earnings call** discussing the possibility of new nuclear build in the early 2020s and NextEra could be following suit if the latest EPA standards force the state to further reduce carbon emissions. NextEra is closely watching SCANA and Southern's progress on their respective projects and given the long lead-time ahead of nuclear development, we would not be surprised to hear management announce its intensions sooner rather than later with respect to its Turkey Point Units 6 & 7 (collectively 2.2GW). FP&L received approval from the Florida Siting Board in May 2014 for the two units and the 2009 application is still pending with the Nuclear Regulatory Commission (NRC). Late in August the NRC voted to end the moratorium on issuing new plant licenses and the Company is optimistic that it can receive its licenses in 2017.

The broader question from Southern and NextEra's contemplation of new nuclear is to what extent the country intends to replace nuclear units that will see their sixty-year licenses expiring in the late 2020/early 2030s. For example, Turkey Point Units 3 & 4 came online in 1972 & 1973. We see this issue becoming an increasingly popular topic in the next few years as the subject gains greater clarity with regulated utilities especially in the context of the latest EPA standards. The discussion of further extensions to eighty-year licenses remains a topic for discussion although retrofits and upgrades would be needed.

Infrastructure remains a hot topic with more expected to come

NextEra wants to be integrally involved in the shifting Southern fuel mix and MVP is only the start of the pipeline buildout.

Following **the announcement of the Mountain Valley Pipeline** (MVP) with majority owner/operator EQT Corp., we expect more updates soon with the binding open season just completed on September 29th. Management characterized the economics of the project as solid at 1.5bcf/day but it is optimistic that the project could reach 2bcf/day, thereby enjoying much better economics. More importantly we expect NextEra, Dominion, and other regional peers to increasingly become involved in midstream plays as they stray outside their traditional regulated utility footprints to capture growth. Despite having a minority stake in MVP, this could potentially be a $1Bn spending opportunity for NextEra and Dominion/Duke's Atlantic Coast Pipeline announcement only reaffirms that fact.

Other investment opportunities

- **Transmission investments** are "inching forward" and we could see some regulatory decisions in the next approximate six months. By 2020 this could be a $50-100Mn net income business (~$35Mn UBSe), potentially worth an incremental ~$1/sh in our valuation.

- **Utility scale solar** could be a big opportunity later in the decade and NextEra has accumulated ~800MW of eligible sites in Florida but management continues to have a less optimistic outlook for distribution generation (DG). On the 1Q14 call management stated that they do not see much of an opportunity with distributed solar.

- **Florida peaker** studies are still progressing and management continues to view this as more of a shift in capex rather than a risk of spending not materializing. While there is competition from other projects, we see the real question as whether the Florida PSC will accept the proposal under its Environmental Cost Recovery (ECR) Rider, rather than through a conventional rate case (as mentioned above, FP&L remains in a rate stay out through 2016).

- **Storage** is a small investment for NextEra today but the company comments that it could be "meaningful" by the end of the decade. Early indications appear to bias towards frequency regulation – and other short term solutions.

M&A: Unlikely for NextEra to pursue Oncor under auction

M&A is important for NEE but the company cautions that it will not pursue a deal unless its strict criterion are met.

While the prospects of acquiring Oncor appear "off the table right now" given the two-tier auction process, we would not rule NextEra out, despite their having withdrawn their bid. NextEra likes Texas and the fundamental Oncor business so it remains to be seen whether management returns to the table in the next ~month. Turning to what NextEra looks for in regulated M&A, one of the most important factors is a jurisdiction with supportive regulators, a characterization which management believes that Texas meets.

What kinds of options does the Mountain Valley pipe hold?

NEE set to follow Dominion's lead.

We look for further data points this Fall around the success of its binding open season and expect further expansions in the upcoming months/years. Dominion's announcement of a $500Mn, 1-1.5bcf/day Supply Header Project off of its Atlantic Coast Pipeline announced just a day earlier is an excellent example of incremental expansion opportunities from a base pipeline.

Don't look for much on the wind development side until PTC clarity

We don't expect management, nor its counterparties, will sign much in the way of further wind deals ahead of pending clarity of a further Production Tax Credit (PTC) clarity in the lame duck session later this year. While investor expectations continue to call for a further 2-year extension (pushing the effective date for project in-service to qualify into 2016, and some into 2017). As a reminder, management has already 1.8GW of backlog, out of the 500MW – 1.5GW range previously articulated at its last Analyst Day.

More solar soon? Utility-scale opportunities still lurk

Management appeared surprisingly confident in its outlook for up to ~400 MW of further utility-scale solar projects, with RFP developments likely to yield formal projects in 2H14. Not only could NEE be awarded some projects in the southeast, but could see further awards in California as well. While we expect the utility-scale market to continue to decelerate (amidst an increasingly competitive field of players), we think management will continue to de-emphasize opportunities in this segment.

Bias remains for utility scale over distributed generation.

Still not stoked on merits of DG – outside of C&I

Management maintained its more sober view on the value proposition of distributed generation amidst a clear preference for large-scale C&I. We flag a clear reticence persists across a variety of companies from entering too aggressively the residential DG market.

NextEra forms Woodford Shale JV with PetroQuest: Opens Ratebase Theme

In one of our NextEra Energy note, '**A Windy, Gassy, Yieldy Opportunity Set'**, we indicated that a gas E&P ratebase proposal was very likely in the near term. It came even earlier than we thought: on June 25th, NextEra announced that Florida Power and Light (FP&L) had formed a joint venture with oil and gas producer PetroQuest Energy (PQ) to develop up to 38 natural gas production wells in the Woodford Shale play (Oklahoma). Under the agreement, PQ will develop and operate the wells, and FP&L will pay a share of the project's capital expenditures (FP&L's portion is estimated at approximately $191Mn NPV) in exchange for receiving natural gas. NextEra anticipates generating up to $107Mn in savings for its customers over the life of the project.

NEE has moved quickly on the gas rate base opportunity

Look for Marcellus focus on future ratebase opportunities potentially

We expect the FL PSC to render its late 2014/early 2015.

Northeast Utilities (Buy; $50 PT)

Nickel miss on mild weather and a slightly higher tax rate

We expect NU to report **$0.73** vs consensus $0.77, with weather -$0.03 vs a very strong 3Q13, with the hottest July on record last year. O&M should be reduced by +$0.03, and transmission ratebase growth of ~$320M will be accounted for at 12.5% ROE pending the final outcome of FERC ROE proceedings in New England. The absence of a -$0.05 transmission ROE charge in 3Q13 helps a nickel, as does +$0.02 of distribution utility growth. Interest, D&A, and property/other taxes hurt a few pennies.

A slight miss on weather for 3Q, with full year tracking toward the lower end of guidance despite some pickups in 4Q from the CL&P ratecase and a lower tax rate.

Figure 138: NU 3Q Walk

3Q14 YoY EPS Waterfall		
	$0.69	**3Q13**
	(0.03)	Hottest July in history in 2013. Normal July this year, cooler August vs normal and yoy, but warmer Sept WMECO is elec decoupling and CL&P gets 2/3 of revenues through fixed charges. NSTAR and PSNH are more affected by weather.
	0.03	O&M - had low O&M in 1H13 from deferred storm work costs into 3,4Q
5	0.01	Transmission ratebase growth YoY ~$320M @ 12.5% ROE (pending final FERC outcome)
	0.05	Had a -$0.05 charge for FERC transmission ROEs in 3Q13
10	0.02	Distribution growth at NU (0.0%-0.5%)
	(0.01)	Interest Savings (only 2/3 non-tracked distribution)
(4)	(0.01)	Depreciation YoY (only 2/3 non-tracked distribution)
(3)	(0.01)	Property & Other Taxes (only 2/3 non-tracked distribution)
	(0.01)	Slightly higher income tax rate (35% vs ~34%)
	$0.73	**3Q14**
	0.77	*Street consensus EPS*
	2.60-2.70	2014 Guidance (includes -$0.10 FERC transmission charge but excludes -$0.03 integration charges)
	2.75	UBSe, excluding the $0.10 FERC transmission charge and the -$0.03 integration charge

Source: UBS estimates, FactSet, and Company Filings

Guidance was actually raised for 2014

On the 2Q call, management reduced the top end of the guidance range by $0.05, updated from $2.60-$2.75 to $2.60-$2.70 vs. consensus of $2.70, including the -$0.10 impact from the transmission ROE reserve. Excluding this impact, the ongoing guidance was actually increased +$0.075 to $2.70-$2.80. <u>We recently reduced our 2014 estimate a nickel to the low end of guidance largely to reflect the milder weather this summer</u> and our TTM calculation of $2.58, excluding the transmission ROE charge. Results for 4Q should be boosted by a $0.07-$0.08 annualized rate increase at CL&P, lower O&M, higher transmission ratebase, and gas sales at Yankee Gas have run strong this year, further helping the outlook. Going forward, our largely unchanged estimates are based on our assumption that CL&P will exit its ratecase earning in the mid-9's ROEs once they are recovering storm expense (see table). NU plans to reduce operating costs by 3%-4% annually through 2017. <u>Despite tracking toward the low end, we do not expect the company to reduce 2014 guidance.</u> We expect NU to initiate 2015 guidance in Feb 2015 on the 4Q call.

Our 2Q and 2014 estimates exclude the 2Q $0.10 transmission reserve charge. We will also exclude an anticipated 3Q -$0.05 charge as well.

Figure 139: NU Earnings Estimates 2013A-2017E

Annual EPS	2013A	2014E	2015E	2016E	2017E
Transmission	$0.68	$0.71	$0.78	$0.81	$0.79
Distribution, Generation	0.95	0.88	1.06	1.09	1.10
Yankee	0.08	0.09	0.10	0.10	0.12
NSTAR, Corp & Other	0.82	1.02	0.96	1.15	1.31
UBSe	**$2.53**	**$2.70**	**$2.91**	**$3.16**	**$3.32**
CL&P Dist ROE	*7.9%*	*6.5%*	*9.4%*	*9.3%*	*9.2%*
Prior		*$2.70*	*$2.91*	*$3.16*	*$3.32*
Consensus	***$2.53***	***$2.68***	***$2.87***	***$3.03***	***$3.21***
Guidance (excluding -$0.10 T-charge)	**$2.70-$2.80**		**6% - 8% EPS Growth**		

Source: Company filings, FactSet, and UBS estimates

What is the latest with the New England FERC ROE challenge? Much ado about nothing

The latest battleground relates to the macro component of the two-step ROE with the New England Transmission Owners (NETO) challenging the GDP component. Specifically the NETO believes that (1) the growth rate is too low at 4.39% and (2) the weighting for GDP at one-third is too high, both of which they argue applies downward pressure on the ROE. The long-term (2017-2040+) GDP forecast comes from the a third party consultant, the EIA, and Social Security Administration (SSA); in our latest mark-to-market exercise we consulted the latest available information from the EIA and SSA noting insignificant changes. For example, if the GDP growth assumption were increased by 10bp, the FERC 75th percentile would increase to 10.60% from 10.57%, a largely immaterial change. A 50bp move would drive a 10.74% ROE; however, such a material upward revision appears unlikely given the data presented.

Figure 140: ROE Analysis Summary

ROE Analysis Summary	*Low*	*Midpoint*	*High*	*FERC 75th %*	*"True" 75th %*
Zone of Reasonableness (Original)	**7.03**	**9.39**	**11.74**	**10.57**	**9.77**
Zone of Reasonableness (1/4 GDP Weight)	**6.97**	**9.51**	**12.05**	**10.79**	**9.84**
Zone of Reasonableness (UBSe MTM)	**6.74**	**9.95**	**13.16**	**11.56**	**9.48**
Zone of Reasonableness (Adj. MTM)	**6.74**	**9.24**	**11.75**	**10.49**	**9.48**

Source: Company Filings, Yahoo! Finance, and UBS Estimates

While this argument may have more weight, it is difficult to quantify the appropriate weights necessary for such a hypothetical analysis. If the weighting is shifted to be (3/4) for IBES Growth Rate [versus (2/3)] and (1/4) for GDP Growth Rate [versus (1/3)], the outcome would be a 22bp increase in the FERC ROE to 10.79%. While this is a more material increase than a minor tweaking of the GDP expectation, given the seemingly arbitrary split between IBES and GDP weighting in the first place, we would expect NETO struggling to provide a detailed analysis to justify such a change in methodology, especially at the eleventh hour.

For more background, see our previous note **6/19/14 Northeast Utilities "A New and Improved FERC ROE Methodology"**.

Despite investor concerns over ROEs, the real impact is from new projects

With New England increasingly in dire need of new capacity, transmission, and fuel options, NU's value lies in its ability to continue to build desperately needed infrastructure over the next decade. This is especially true given the constraints exposed in the natural gas system this past winter, with the problem poised to worsen significantly after the planned shutdown/retirement of another 1,400 MW

by yearend (including the 1,200-MW Vermont Yankee nuclear station). Even if FERC's recent reduction of transmission ROEs stands as-is, earnings are reduced only ~$0.05-$0.06 EPS without any material affect the company's projected EPS growth CAGR of 6%-8% from 2012-2017. We see continued merit to NU executing on its NPT line and while we remain somewhat skeptical of the NESCOE process, it undeniably highlights the presence of significant investment opportunities for NU, including the recently proposed Access Northeast pipeline in partnership with Spectra (see below).

NU's Connecticut ratecase settlement possible, but not this month

November could be quiet in CT.

We see resolution on the case as the key incremental datapoint for shares in 2H14

To the extent that a settlement is possible, we don't expect to hear of anything in Northeast Utilities' CL&P ratecase this month, although we think that a settlement of the case is somewhat more likely this time around without the former Attorney General Richard Blumenthal to knock down any deal. With a draft decision due December 1, any possible settlement would probably come in the Oct/Nov timeframe, earliest. A final decision is due December 17. In early August, the CT Office of Consumer Counsel (OCC) filed testimony recommending a $143M increase (vs $232M ask) based on an 8.9% ROE. We consider the 8.9% to be the low-end of expectations for a final outcome later this year, with a bid/ask midpoint of 9.55% a reasonable expectation vs the currently authorized 9.4%. We expect a ~150 bps rise in earned ROE beginning December 1, 2014 and beyond as a result of finally being allowed to recover and earn a return on $286M of net deferred storm expense and resiliency investment. The returns on storm cost and investment should boost earned ROE to the mid-9%s, allowing CL&P to earn its allowed ROE for only the second time since 2004 (it also achieved this milestone in 2011). We further note that under the earnings sharing mechanism, shareholders retain 50% of all earnings above the authorized ROE and that state law allows the utility to over-earn by as much as 100 bps before a mandatory rate review.

What's the latest on Northern Pass?

Winter volatility should draw support for Northern Pass

Management continues to express confidence that following the polar vortex of this past winter, the tone is shifting to be more supportive of the project but investor concerns are still palpable. <u>The final Environmental Impact Statement is more likely to be a 1Q15 event rather than December</u>, followed by an application with the New Hampshire Site Evaluation Committee. We would expect to see the latest cost estimate for the project in December 2013/January 2014.

Latest DOE comments suggest yet another route change is likely late this year with EIS

Expect updated cost estimate in January, 2015

The recently released DOE comments includes an analysis of alternate rounds, including undergrounding of certain 'sensitive' areas but management stated that none of the options would impact their schedule of ultimate regulatory approval in 2015 and project completion in 2H17. As proposed currently, the project has eight miles of undergrounding (vs. 50+ miles for Blackstone subsidiary Transmission Developers Inc. [TDI]) and we would not be surprised to see management concede on further undergrounding in order to push the project past the final regulatory hurdles.

Question remains how HQ will react to the offer to socialize transmission costs across ISO-NE

Despite the ongoing retirement of 1,400 MW of non-gas generating capacity (including Vermont Yankee) in 2014, it remains unclear where the electric transmission proposal stands and whether HQ will push NU to shift the contract back to a socialized option if possible, spread across all of New England's customers. While NPT is clearly in the lead, this complicating factor remains our primary concern over the viability of competing projects, such as the TDI proposal or the New England NALCO project. Overall, we think incremental electric

transmission remains the clearest way to address the current shortfalls in the region.

New Hampshire divestiture looks a little less likely with rates rising

There may now be second thoughts over the wisdom of divestiture with higher energy rates from the polar vortex set to rise on Jan 1 for non-NU utility (Liberty, Unitil) bills due to their reliance on gas generation contracts.

The company has been generally supportive of HB 1602, which would have the PUC go through a docket to determine whether or not PSNH should divest its generation, beginning no later than Jan 1, 2015 and likely completing the review within a year. However, there may be second thoughts over the wisdom of divestiture with higher energy rates from the polar vortex set to rise on Jan 1 for non-NU utility bills (Liberty, Unitil) due to their reliance on gas generation contracts. We estimate that about 25% of New Hampshire customers (non-NU) will soon see their energy rate almost double to $0.15/kWh and their total retail rate jump from $0.15/kWh to $0.22/kWh. National Grid customers will likely see their energy rate rise to $0.13/kWh. More broadly speaking, other non-NU utility rates in CT, MA and NH are probably going see energy rates rise from $0.14 to $0.23-$0.24. CL&P's energy rate could rise to $0.13 with a total retail rate of about $0.225 (depends on the final CL&P rate order), and NSTAR's and WMECO's energy rate should rise to $0.14-$0.15 with a total retail rate of $0.23-$0.245. In contrast, PSNH's energy rate (applicable to roughly 75% of all NH customers) will likely stay flattish at $0.09-$0.095 with a total retail rate of $0.17-$0.175/kWh due to its unique reliance on cheaper, ratebase coal, biomass, and hydro. NU estimates that its customers saved over $100M during the Polar Vortex, with even more benefits to come as rates rise in New England from its constrained gas market.

Figure 141: Bills Heating Up This Winter in New England

NU Winter 2014/2015 Pricing Expectations		
Utilities	**Energy**	**Total Bills**
NSTAR & WMECO	$0.14-0.15	$0.23-$0.25
CL&P	$0.13	~$0.23
PSNH	$0.10	$0.18

Source: Company Filings and UBS Estimates

On a percentage basis, energy rates should be averaging 50% higher on Jan 1 than they are today with some of the small NH utilities and Massachusetts Electric (Grid) up around 90%. In contrast, PSNH's total retail rate should actually decline a bit (flattish), CL&P's retail rate should increase "only" 15%-20%, while the small NH utilities will likely raise retail rates about 45%. We note that these higher rates would apply only to the 6-month winter period and that rates are likely to decline significantly for summer 2015.

The PUC recommended to legislators not to begin a separate divestiture docket until they are finished with the Merrimack scrubber docket, which should go through the end of 2014, with hearings beginning October 14. NU has been generally supportive of the divestiture law, with the understanding that current statutes would protect the company from any potential stranding of the associated ratebase. In any event, the earliest a divestiture would actually take place is 2016, if at all.

Worst case Merrimack represents only ~5% EPS impact today

We believe any decision on divestment appears only likely subsequent to a decision on how to address cost recovery on the associated scrubbers, with that docket wrapping up by year end. We flag that the latest winter shortages and extreme pricing may yet have driven an evolution in states' thinking both with regard to using the generation as a hedge *and* with regards to preserving more regional

assets (although the latest run up makes Merrimack FCF positive once again on a merchant basis). We believe asset value has substantially improved in recent months, suggesting some [very modest] proceeds from any sale (although the latest bump in capacity prices – and shift towards a sloped demand curve go a long way towards creating some value as indicated by NextEra's decision to retain its Maine generation), reiterating the need to establish a 'prudent' cost on the Merrimack scrubber. The coal plant is far and away the largest component of generation ratebase at 534MW, out of the 1.1 GW portfolio. We believe the key question remains around recovery on capital (ROE), not return of capital employed (D&A), although there is a separate ongoing process around the prudency of the Merrimack scrubber spend that remains pending, and a slight headwind. In a worst case outcome, we estimate this represents just a $0.05 EPS impact, without any sale proceeds for the 1.1GW portfolio. We also note that should the scrubber capex be approved into ratebase, the current deferral of $70M-$80M would likely be amortized over 5 years, and annual EPS would rise about $0.03.

NESCOE process slowed down by failed legislation; RFP by December?

We think NESCOE may be a dead-end for now

Without more gas, we emphasize the need for new electric transmission is all the more dire

The New England States Committee on Electricity (NESCOE) had been expected to provide a schedule for its RFP by September for the development of transmission and delivery of at least 1.2-3.5 GW of clean energy into New England. However, this is now highly likely to be postponed through Nov/Dec as a result of the failure of Massachusetts to pass a Clean Energy Bill on July 31. The Bill would have allowed the state to enter into long-term contracts for ~19 TWhs of hydroelectricity from Hydro Quebec, essentially providing backstop financing for new power lines intended to be developed under a NESCOE RFP. Similar clean power procurement legislation already exists in Connecticut. Press reports indicated that environmental group opposition to hydropower in favor of wind and solar were a key factor in the Bill's demise. With no chance of any similar legislation this year, NESCOE's plan to file for two new tariffs to fund both electric transmission and new gas pipelines into New England have stalled as the states reconsider how to proceed. We don't see any RFP possible before elections as both Mass and RI will have new Governors (no incumbent running in either state).

NU Partnering with Spectra on Access Northeast to reduce NE gas constraints

NU and Spectra Energy (SE) announced a $3Bn, 1+bcf/day Access Northeast natural gas JV which designed to address New England gas bottlenecks. The project is a combination of additional pipeline capacity/expansions & storage facilities which will interconnect with Spectra's existing assets. NU & SE will be collecting solicitations of interest through Oct and will work with ISO-NE and NESCOE in Dec before beginning the FERC regulatory approval process next year. The project is not expected to be online until Nov '18 (earliest), leaving four winters before the true benefits of improved supply.

NU and SE take the lead, but lack of generation offtakers is the real issue

Previously National Grid and UIL were involved in the proposed NESCOE solution but now Spectra and NU will be equal partners in the project "with the option of additional investors joining in the future;" we still look for partners to come aboard with NU/SE jointly sharing the excess. NU may view the utilities as a "natural solution" to solving gas constraints but the issue still remains as to whether the Electric Distribution Companies can recover FERC-approved tariffs

from electric retail customers, seeing generators as unable to fund upgrades. As SE management pointed out on the call, the market reforms are key to allow the recovery of cost of generation, with some potential for incremental gas LDC contracting. Reforms remain critical to projects materializing- and with NESCOE stalled – we sense a long road ahead for midstream gas developments.

Mass natural gas distribution work set to accelerate significantly

Accelerating the rate of conversions in Massachusetts would be a big boost for NU with residential gas penetration still below 50%.

At the February Analyst Day, NU forecasted $215M/yr of total natural gas distribution capex for the three years from 2015-2017. However, as a result of new Mass legislation, that projection is very likely to increase, perhaps by $150M-$160M for the period.

Gas main replacement riders: New legislation in MA was passed in June to expedite the replacement of cast iron and unprotected bare steel gas distribution mains and to expand the state's natural gas distribution network over the next 20 years. The law provides for separate carve-out investment recovery mechanisms. Once NSTAR Gas files its required expansion plan with the DPU, regulators will have 8 months to review and approve it.

Oil-to-gas conversion: The legislation also minimizes lag in oil-to-gas conversions and promote area gas charges that would help share costs of conversions and ultimately would be another catalyst towards the high-end of the long-term earnings growth rate for NU. The penetration for residential natural gas heating sits at 48% and 32% for MA and CT, respectively, far lower than that of neighboring New Jersey (72%), highlighting the scale of the opportunity here.

LNG Storage: NSTAR is working on a MA recovery mechanism for significant investment needed at its affiliate-owned 3.2 BCF Hopkinton LNG storage facility.

NSTAR Gas to file first ratecase in over 20 years: In May, NSTAR Gas notified the MA Department of Public Utilities (DPU) that it intends to file a ratecase before the end of the year (rates effective in 2016), the first case for them in more than 20 years.

Valuation: Maintain $50 PT

Our valuation is based on a utilities sum-of-the-parts analysis. We continue to apply the peer multiple (now down a full turn since the analyst day at 14.0x 2016E) to the regulated electric/gas businesses as well as 1x and 3x premiums to Yankee Gas and NU Transmission, respectively. We continue to attribute ~$3/sh to the Northern Pass project and believe investors could more fully ascribe this in their valuations in 2014 as key project hurdles are achieved. As we discussed above, we believe a key for shares will be investors gaining comfort in estimates even without Northern Pass' contribution as there are other levers that management can pull to compensate such as the novel gas investment opportunities and New England RFP.

We see attractive value in shares given that shares trade at a slight discount for a company that appears particularly well positioned to see constructive capex revisions in coming months. With the story likely to diversify beyond just NPT, and with ~5-6% estimated EPS growth without any spend there either, the thesis looks increasingly attractive in a slowing growth environment. Our key thesis for the sector remains broadly to invest in regulated utilities in regions with significant policy ambitions, enabling investment opportunities irrespective of the slowdown in projected utility sales.

Figure 142: NU Sum-of-the-Parts Valuation

			Low Case		Base Case		High Case	
	Valuation		Valuation	($s MM)	Valuation	($s MM)	Valuation	($s MM)
Business Segment	**Metric**	**2016E**	**Multiple**	**Value**	**Multiple**	**Value**	**Multiple**	**Value**
Regulated Business					**Peer Multiple**	**14.7x**		
NU Franchised Electric	P/E	$1.09	13.74x	$4,739	14.7x	$5,084	15.74x	$5,429
NU Transmission	P/E	$0.81	16.10x	$4,126	17.1x	$4,382	18.10x	$4,639
NU Yankee Gas	P/E	$0.10	14.74x	$485	15.7x	$518	16.74x	$551
NSTAR	P/E	$0.95	14.24x	$4,291	15.2x	$4,593	16.24x	$4,894
Northern Pass EPS, Discounted 1	P/E	$0.23	13.74x	$1,007	14.7x	$1,081	15.74x	$1,154
NU Equity Value				$14,649		$15,658		$16,667
Fully Diluted Outstanding Shares (2016E)				316		316		316
NU Equity Value per Share				**$46.33**		**$49.52**		**$52.71**

Source: Company filings and UBS estimates

Agreeing to keep the lights on in New England for another winter

New England getting more serious about LT solution but approving another 'one-off' winter

In September the FERC approved ISO-New England's (ISO-NE) request to once again implement a winter reliability plan (the Plan) for the upcoming 2014-2015 winter to incentive enough procurement of primarily oil to ensure adequate reserves. Although the Commission agrees that an out-of-market plan will be necessary this year, FERC argues that it is "closer to a market based solution" than it was previously. Oil will be compensated at $18/barrel for generators that enter the winter with either less 85% fuel capacity or ten days of fuel. 2013-2014's program led to the procurement of three million barrels of oil with ~90% being utilized with this year's Plan increasing inventories by 500k barrels. Other reforms include tweaks to the dual-fuel incentives and a move to a March 15th measurements. In the past the FERC has encouraged ISO-NE to begin a stakeholder process for a longer-term solution; however, this year appears to be more serious about finding an answer by mandating that ISO-NE begin a stakeholder process by year-end with bimonthly reporting requirements. The ISO also announced that it plans to begin the process within the next ~two months, well ahead of the mandate; a meeting schedule is required by October 9th.

Docket ER14-2407-000

LNG imports into New England? Unlikely to materialize in any real volume

The Plan also 'incentivizes' the procurement of up to 6 bcf of LNG with compensation at $3/MMBTU, essentially in-line with oil, the latter much to the dismay of GDF Suez. United Illuminating (UIL) proposed compensation at $8/MMBTU but ISO-NE pushes back that "it is not economically practical to pay more for LNG than for oil", effectively taking the standpoint that it will not fully compensate generators who opt for a more expensive fuel source. In a similar vein, FERC fully acknowledges that the Plan is not fuel neutral and does not provide the same compensation to nuclear or hydro operators who cannot simply stock-up on additional fuel (points argued again by PEG and EXC). We fully expect PEG, EXC, and other 'disadvantaged' generators to push for a more beneficial solution before the Pay-for-Performance system is implemented in June 2018.

NRG Energy (Buy, $35 PT)

Even with pickup from Alta Wind consolidated EBITDA we estimate ~flat EBITDA for 2015E. Look for management to shift focus to capital deployment and solar DG strategy.

Adjusted EBITDA could decline slightly YoY versus consensus expecting improvement.

We estimate that NRG Energy will report 3Q14 adjusted EBITDA of **$973Mn**, modestly light of consensus and importantly down YoY given weaker pricing. We expect relatively soft results going into 2015 and anticipate commentary to focus on capital allocation and the much anticipated solar strategy.

2015 guidance could look flattish is but focus could shift to per share basis.

While previously management characterized its early 2014 performance as "a running start on a good year", the lackluster weather this summer has tempered expectations. With 2Q14 results CFO Kirk Andrews stated that "absent above average weather over the balance of the summer or colder weather later in the year, we expect our actual financial results for 2014 would be towards the lower end of these ranges." Although the Alta Wind deal did not close until mid-August, we view the $45Mn contribution here as key to keeping FY14 consolidated adjusted EBITDA as **near the midpoint of the $3.2-$3.4Bn guidance range.** If NRG Energy does discuss capital allocation and a potential buyback, we would look for management to frame growth on a per share basis.

Figure 143: 3Q14 Earnings Walk

EBITDA ($Mn)	3Q13E	2013A	3Q14E	4Q14E	2014E
NYMEX Assumption					*4.26*
Texas	216	502	180	95	361
Northeast	409	1,004	248	224	1,153
South Central	33	43	47	72	179
West	60	167	133	132	371
Alt Energy & NYLD	52	335	80	68	427
Retail Businesses	176	614	251	164	695
Corporate, Other, and Unallocated Synergies	54	(29)	35	75	105
NRG Adj. EBITDA (UBSe)	1,000	2,636	973	830	3,290
Prior EBITDA Est. (UBSe)					3,281
Consensus EBITDA Est.(10/13/14)	1,000	2,636	1,048	740	3,298

Source: Company Filings, ThomsonReuters, and UBS Estimates

Links to our relevant recent research are below:

9/12/14 Recharging the Batteries

8/20/14 After a Strong Year the Question is What's Next?

5/28/14 Extracting the Upside from All of Power's Facets

2015 Guidance Expectations: Flat

We continue to see consensus estimates as largely capturing a realistic view on forward estimates for the consolidated company. Our 2016E estimate is up $210Mn; however, it would have declined if not for the Alta Wind deal at NRG Yield. With our $3,340Mn 2015 consolidated Adjusted EBITDA estimate we look for management's initial guidance range for the year to be the same as its current range: **$3,200-$3,400Mn**. Capital allocation could provide upside to this but the solar DG opportunities are unlikely to drive a material contribution in the near-term but are more of a 2016+ story.

When incorporating uplift from Alta, we still see ~flat EBITDA estimate next year.

Figure 144: Updated NRG Energy EBITDA Estimates – Reflecting Alta Wind

EBITDA ($Mn)	3Q13E	2013A	2014E	2015E	2016E	2017E	2018E
NYMEX Assumption			*4.26*	*3.87*	*4.00*	*4.15*	*4.32*
Texas	216	502	361	374	331	316	174
Northeast	409	1,004	1,153	806	769	669	719
South Central	33	43	179	115	115	143	193
West	60	167	371	394	383	395	330
Alt Energy & NYLD	52	335	427	597	634	631	628
Retail Businesses	176	614	695	659	620	586	616
Corporate, Other, and Unallocated Synergies	54	(29)	105	393	392	387	387
NRG Adj. EBITDA (UBSe)	1,000	2,636	3,290	3,338	3,244	3,127	3,047
Prior EBITDA Est. (UBSe)			3,281	3,160	3,038	2,958	
Consensus EBITDA Est.(10/13/14)	1,000	2,636	3,298	3,216	3,081	2,950	
Guidance (2Q14)		2550-2600	3200-3400				

Source: Company Filings, ThomsonReuters, and UBS Estimates

Where to focus in the balance of year?

While the cool summer could dampen 2014 adjusted EBITDA, we believe management will have levers to pull to reignite shares and force investors to look past any short-term hiccup. With our expectation of lackluster 2015 guidance, we believe the 3Q call could include more forward looking thoughts.

Following discussions with management, we include several upcoming developments which could yet enable a recovery in shares off their low.

Articulating the retail solar story is among the next critical steps.

We think NRG Energy might be approaching the tipping point on being able to discuss its retail aspirations with the Street with more details, specifically the advantages to its increasingly integrated platform to develop customers economically (employing the Yield vehicle) as well as leveraging its existing customer base to cross-sell. While the business will clearly take some time to reach 'critical mass', with competitors still largely in their infancy, we think NRG could yet take market share in competitive states (largely focused on the Northeast, including New York and Massachusetts).

What has management recently acquired?

While few details around the business have yet to be disclosed, we emphasize

Building out the 3-2-1 strategy value pyramid.

- **Rooftop Diagnostics:** Seeing its position as the largest northeast installer of solar rooftops, particularly in NJ, we see this acquisition as the most important by NRG to become an integrated developer. NRG appears keen to own customers fully, rather than monetizing to third-parties. Importantly, it appears it needs to be integrated in order to compete in the sector. We flag the move into residential solar itself follows more cautious starts on deepening its direct solar business from a range of peers, including NEE.
- **Goal Zero:** This acquisition appears the oddest in the bunch of late, as management has positioned itself into the world of solar-powered gadgets. It's unclear how management intends to feed this into its conventional grid-business yet.
- **Pure Energy Deal:** Web-based customer acquisition of solar customers is rapidly becoming a focus in the solar sector – given NRG's experience in web platform selling retail in Texas through the particularly competitive PowerToChoose website, we are not surprised to see management move in this direction necessarily.

Figure 145: NRG Renewable Development M&A – More to Come?

Announce Date	Close Date	Deal Type	Deal Title
2 Oct '14	TBD	DG Solar Related	NRG Energy acquires Pure Energies Group
14 Aug '14	18 Sept '14	DG Solar Developer	NRG Energy acquires Goal Zero
27 Mar '14	27 Mar '14	DG Solar Developer	NRG Energy acquires Roof Diagnostics, Inc.
09 Jan '13	09 Jan '13	DG Solar Developer	NRG Energy acquires Sunora Energy Solutions I LLC from GCL Sunora, Inc.
21 Nov '11	21 Nov '11	DG Solar Developer	NRG Energy acquires Solar Power Partners, Inc.
21 Jan '10	21 Jan '10	Wind Development	Enel NA acquires Padoma Wind Power LLC from NRG Energy, Inc.
09 Nov '09	09 Nov '09	Wind Development	NRG Energy acquires Bluewater Wind LLC from Babcock & Brown Ltd.

Source: FactSet, SNL, and Company Filings

How much is being burned for residential solar– and where's the return?

Embedded within management's 2014 EBITDA guidance is a **$40 Mn EBITDA drag** from the company's nascent solar business, which has pursued a number of potential transactions this year. Management appears confident it will be able to articulate specific turn-around in this business as it seeks to put to rest these concerns. We see this drag as in-part driving the business to the bottom end of its contemplated 2014 range pre-Alta Wind contribution.

Northeast opportunity has significant savings for NRG Energy

As we depict in the Figure to the right, if NRG Energy is able to convert 10% of its post-Dominion Northeast customers to solar, it could have **$150Mn of value** from its ~60,000 solar customers if using a $3,000 cost of customer acquisition. Specifically NRG Energy had 2.9Mn customers as of its 6/30 filing with ~2.2Mn in Texas, implying ~700K in the Northeast. The company expects attrition from its Dominion acquisition with a target of 500K customers, down from 600K+ announced with the deal. This pool of value would need to be split between NRG Energy and NRG Yield and while a material number, as NRG Yield grows the potential accretion naturally declines.

Figure 146: Estimating the NRG Customer Conversions

As of June 30, 2014	Thousands
Total Customers	2,921
Texas Customers	2,200
Northeast Customers	721
FY14 (UBSe)	Thousands
Dominion Acquisition	600
Dominion Attrition	100
Total Customers	2,821
Texas Customers	2,200
Northeast Customers	621
NE Solar Conversion	10%
Solar Customers	62
Value per Customer	$3,000
Potential NRG Energy Value ($Mn)	$186

Source: Company Filings and UBS Estimates

Repurchases back on the table, with capital allocation plan?

Reading between the lines? We see CEO Crane's latest move as equity price endorsement

Given the sharp share price reaction to recent developments (down 15%+ in past three months), we anticipate management will be keen to articulate its 2015 capital allocation plan (typically alongside 4Q results, if not sooner), with a focus on repurchasing even a modest level of shares. Management has not repurchased sizable quantities of shares since 2011. Discussion of a modest amount of buyback could even be on the table for 3Q (earnings announcement expected around EEI Financial Conference in early November), with ~$300Mn of FCF available still at NRG Energy to deploy (attempting to offset commentary with 2Q, suggesting any further capital deployment was a ~2015 issue).

While modest in real impact, CEO Crane opted to cancel his 10b5-1 shareholder monetization program, expressing yet further confidence in the company following its current pullback.

Bottom line, NRG continues to leave open the door to addressing (at least initially) capital allocation earlier than its historic 4Q results as questions continue to mount. We believe with shares down of late, management could well accelerate plans, particularly amidst greater scrutiny of growth plans.

Cost savings? Interest savings still available

With the credit markets remaining robust, NRG appears keen to continue to refinance existing debt on better terms. While Calpine continues to execute on advantageous refinancings to improve go-forward FCF, we believe such transactions could yet be particularly accretive to NRG Yield's project subsidiaries.

Specifically Walnut Creek on deck for a refinance

While too substantial, we estimate a $2-3 Mn/yr interest reduction in its distributable cash flow on any refinancing, off a base of $35 Mn in estimated CAFD. We believe details could yet be released around a drop of the asset into NRG Yield (discussed in the NYLD section subsequently – we estimate a 10x EV / EBITDA drop price, or a $540Mn purchase price).

Readying the next round of drops: the question is price

For the balance of the year, we think management will look to execute on the next round of drops to NRG Yield. Specifically, we anticipate Walnut Creek will attract meaningful attention, with a close focus on implied EV/EBITDA on the asset with only ~9-years of term life remaining. <u>Given the significant uncertainty of terminal cash flows in California for thermal assets, we see this as among the more closely scrutinized transactions from a governance perspective</u>.

SDG&E formally issues RFO for California Capacity

This Summer SDG&E (SRE) management formally issued its long-awaited RFO for new capacity resources in Southern California on the back of the SONGS retirement. We flag it simultaneously filed for the CPUC to approve a 20-year contract for a 600 MW new-build peaker at Carlsbad (Encina) with NRG. While there is some amount of contract execution risk given the lack of an open RFO process, we believe the project remains among the best situated (closest to SONGS site).

SDG&E will look to acquire a *further* 200MW of 'preferred resources' (largely renewables, but could also include demand response, as well as include the first 25MW of storage as part of the CPUC's latest storage effort). We see this solicitation as driving among the few utility-scale contracting opportunities for solar in the state given its largely saturated market position to meet its RPS obligations.

California market evolution points back to a longer contract tenor?

In discussing the merits of the Carlsbad plant, we flag the proposed contract would include a <u>20-year tenor</u>, in contrast to the shorter 10-year tenor seen on all other procurements in recent years for conventional gas capacity. We see this as a particularly constructive datapoint in creating more 'Yield' eligible assets for NRG, as well as the market overall.

We think the shift in tenor is due to more advantageous terms offered by NRG on a 20-year deal (vs 10-years) on an NPV to the Commission, as well as higher assumptions on 'merchant' terminal value by SDG&E given the push by the CAISO to retain capacity at greater tenor (implicitly at a slightly higher price).

Figure 147: Snapshot of ROFO Drop #2

NRG ROFO Asset Drop #2: ($Mn)	
EBITDA and CAFD Guidance	
Run-Rate EBITDA	120
Run-Rate CAFD	35
Project Debt (as of 6/30)	
Walnut Creek	409
Tapestry	196
Laredo Ridge	67
Total Debt	672
EV / EBITDA (UBSe)	10.0x
Implied Purchase Price	528
Debt Financing (Targeting 3.25x Corp Debt/EBITDA)	100
Equity Financing	428
Gross CAFD Yield	8.2%
Total Debt / EBITDA	6.4x

ProForma Financing	Pre-ROFO 2	Post-ROFO 2
Corporate Debt	845	945
Corporate EBITDA (CAFD)	257	257
Corporate Debt / EBITDA	3.29x	3.68x
ROFO Drop 2		
Corporate Debt Latitude	114	
Corporate EBITDA (CAFD)	35	
Corp. Debt / EBITDA Target	3.25x	
Financing at Target Mix	1,200	
Project Debt Assumed	672	Adjustment
Corporate Debt Issued	100	14
Equity Issuance	428	

Source: Company Filings and UBS Estimates

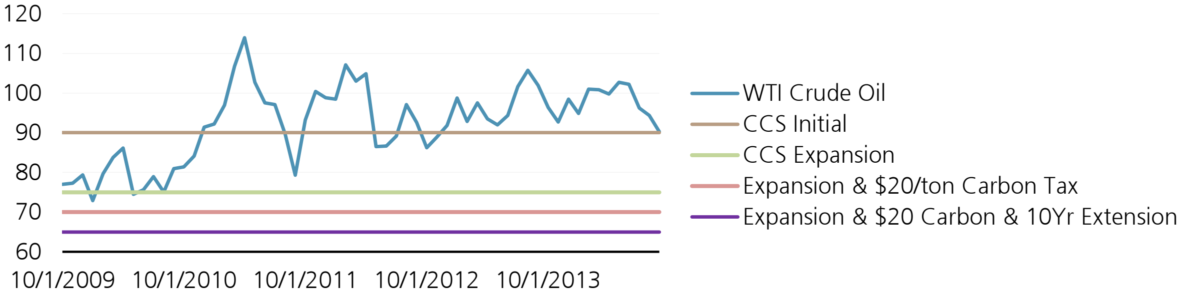
Crude Slump Puts Petra Nova in an Early Hole

With crude approaching a four-year low, value proposition of Petra Nova grows cloudy.

Crude around $85/barrel is now approaching a four-year low as Saudi Arabia has commented that it is "comfortable" with pricing at $80/barrel. Kuwait has made similar statements and does not see reduced OPEC production as likely in the near-term. NRG's Petra Nova project is premised on $90/barrel crude to meet its target 10% return with the initial assets and $75/barrel with the expansion. Assuming that the price of crude remains depressed, this implies that NRG and partners need to undertake the expansion to achieve the desired return.

Management stressed in its last call that Petra Nova is not 'drop-downable' yet but could be in the future; however, we would not anticipate any real update with the project still in its early development stage.

Figure 148: Historical WTI Crude Oil Prices and NRG Energy Guidance for Target 10% Return ($/bbl)



Source: FactSet and Company Guidance

Latest Price Target: Maintaining $35 Price Target

Our 2016E valuation remains based on a sum-of-the-parts with a 9x EV for most core segments. We note that using NRG Yield's current valuation versus our Price Target would trim the valuation by ~$1.50. Shares have largely remained rangebound for the past six months between $29 and $31 with the recent slump back towards $29 likely reflecting at least a portion of the underperformance in NRG Yield in the past ~45 days.

Figure 149: Updated NRG Energy Valuation

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	331	8.0x	9.0x	10.0x	2,648	2,979	3,310
Capacity Pmts @ $60/MW-day (0% probability at this time)	-	8.0x	9.0x	10.0x	-	-	-
Northeast	583	8.0x	9.0x	10.0x	4,668	5,251	5,835
GenOn Operating Leases	80	8.0x	9.0x	10.0x	640	720	800
South Central	115	8.0x	9.0x	10.0x	918	1,033	1,148
West (ex-EME)	150	8.0x	9.0x	10.0x	1,204	1,354	1,505
Alt Energy (ex-NYLD and EME Portions)	181	11.0x	12.0x	13.0x	1,990	2,171	2,352
Retail Businesses (Reliant, GM, E+, Ex-Dominion)	620	4.0x	5.0x	6.0x	2,480	3,100	3,721
Edison Mission	Removed TX capacity payments earlier in '14						
EME - MidWest Generation	155	8.0x	9.0x	10.0x	1,242	1,397	1,553
EME - EMMT (Trading)	32	4.0x	5.0x	6.0x	126	158	189
EME - NYLD (Wind)	101	11.0x	12.0x	13.0x	1,111	1,212	1,313
EME - NYLD (Walnut Creek CCGT)	84	7.0x	8.0x	9.0x	588	672	756
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	2,873	6.8x	7.8x	8.8x	19,642	22,515	25,388
Less: Net Debt (ex-Solar/Non-recourse related)					Adjusted for	(10,684)	
Less: Total Solar Project Finance debt					monetization of 1st	(1,340)	
Less: Total Project debt for Non-Recourse Projects (El-Segundo, etc. removed)					ROFO assets	(383)	
Less: PV of Operating lease of GenOn Mid-Atlantic Lease						(784)	
Less: PV of Operating lease of REMA Lease						(404)	
Less: PV of Powerton/Joliet Operating Lease (As of 6/30/14 at 10% discount rate)				Reflecting latest		(224)	
Less: Midwest Gen Compliance Plan				MidWest Gen plans		(545)	
Less: Assumed EME Debt net of segment cash/non-core						(209)	
Less: Preferred Shares						(249)	
Add: NPV of Solar Accel Depreciated Tax Benefits (Upside with EME wind PTCs?)						1,047	
NPV of Equity using Hedged EBITDA Methodology					5,868	8,742	11,615
Open Analysis							
Power Hedges	(167)	8.0x	9.0x	10.0x	(1,333)	(1,499)	(1,666)
Coal Hedges	5	8.0x	9.0x	10.0x	40	45	50
Total	(162)	8.0x	9.0x	10.0x	(1,292)	(1,454)	(1,616)
add NPV of Power Hedges						496	
add NPV of Coal Hedges						(27)	
NPV of Equity using Open EBITDA Methodology					5,045	7,757	10,468
NYLD -> UBS Price Target					46.00	54.00	65.00
NYLD Equity Value					2,999	3,521	4,238
$/share for NRG Energy (@ 66% Ownership)					6.48	7.60	13.86
Projected Shares outstanding					306	306	306
Equity value per share (using Avg of Open/Hedged)					$24.33	$34.59	$49.98

Source: Company Filings and UBS Estimates

NRG Yield Inc. (Neutral; $54 PT)

Enhanced clarity on the rooftop solar strategy and likely announcing pricing/timing on the Walnut Creek

We estimate that NRG Yield will report 3Q14 Adjusted EBITDA and Cash Available for Distribution (CAFD) of **$123Mn** and **$77Mn**, respectively, essentially in-line with management's quarterly guidance although EBITDA consensus is notably higher ($151Mn). As with previous quarters for the predictable YieldCo, focus will be on forward-looking statements around the upcoming Walnut Creek drop-down (timing and pricing) as well as NRG Energy management potentially providing financial metrics around its rooftop solar opportunity.

We look for an announcement on the next 785MW ROFO drop ($120Mn/$35Mn Adj. EBITDA/CAFD) – we assume a 10x EV / EBITDA price.

Figure 150: 3Q14 Earnings Walk

NYLD Metrics	2013A	1QA	2QA	3QE	4QE	2014
Adjusted EBITDA						
UBSe	244	69	109	123	151	451
Guidance	240	61	75	120	158	455
Consensus	*238*	*63*	*81*	*151*	*172*	*461*
Cash Available for Distribution						
UBSe	91	24	38	77	5	141
Guidance	81	12	22	74	10	145
Consensus	*N/A*					*N/A*

Source: Company Filings, ThompsonReuters, UBS Estimates

Links to our relevant recent research are below:

9/12/14 Recharging the Batteries
8/20/14 After a Strong Year the Question is What's Next?
7/25/14 Celebrating the YieldCo's Anniversary with a PPA
7/22/14 NEP Initiation: Getting Winded

Putting Together the Pieces on Guidance

It is unclear whether NRG Yield will announce 2015 guidance but we present below the pieces although note that the Alta Wind guidance is not reflective of 2015 but instead is a longer-term run-rate.

Figure 151: NRG Yield Assets and ROFO Asset Guidance

Guidance Reconciliation	EBITDA	CAFD
Core IPO + ESC	299	122
Alta Wind	220	70
ROFO	435	165
El Segundo+TA High+Kansas	100	30
Walnut+EME Wind 1 (Tap+Laredo)	120	35
Ivanpah+Agua Caliente	100	45
CVSR	50	25
Remaining EME Wind (816MW)	65	30
Total	**954**	**357**
UBSe (CAFD is Gross)	970	359

Source: Company Filings and UBS Estimates

Abengoa Yield 1st Drop-Down at ~11x EV / EBITDA Looks In-Line With Renewable Expectations

Abengoa Yield announced its first drop-down from Abengoa with the newly formed subsidiary purchasing 181MW of international solar (131MW) and wind (50MW) for $323Mn and the assumption of ~$600Mn of debt. We estimate that the assets generate EBITDA of approximately $80Mn, implying an 11x EV / EBITDA multiple which matches our expectations for long-term contracted renewable transactions between YieldCos and sponsors. Gross CAFD guidance is $27Mn and after accounting for financing (we assume 70%/30% debt/equity financing) and a distribution reserve we arrive at net CAFD of $20Mn, resulting in an 8.9% equity yield. Management is targeting a 3-4x debt / CAFD which guides our financing assumption, which results in an 8.6x debt / EBITDA. For comparison, NRG Yield's purchase of Alta Wind implies a 9.5x Debt / EBITDA multiple. As elaborated on below, we continue to assume that NRG Yield and NextEra Energy Partner will purchase long-term contracted renewable assets from their respective sponsors at an 11x EV / EBITDA multiple and Abengoa's latest serves as another constructive data point.

We estimate that ABY's first drop-down is not similar from peers with an 11x EV / EBITDA. With 70% debt financing assumption the net equity yield would be nearly 9%.

Figure 152: Abengoa Yield First Drop-Down Estimates

Abengoa Yield Drop Down #1 ($Mn)	
323	Purchase Price
226	Equity (70%; UBSe)
97	Debt
600	Debt Assumed
923	EV
81	EBITDA (UBSe)
11.3x	EV / EBITDA
27	Gross CAFD (Guidance)
5	Less: Interest Expense
22	Post-Financing CAFD
2	Less: Distribution Reserve
20	True CAFD
8.6x	Effective Debt/EBITDA
3.6x	Debt / Gross CAFD
Guidance: 3-4x Debt / CAFD	
2.9%	Gross EV Yield
2.2%	Net EV Yield
11.9%	Gross Equity Yield
8.9%	Net Equity Yield

Source: Company Filings and UBS Estimates

Figure 153: Summary of Estimated YieldCo Drop Multiples

Summary of YieldCo Drops	
Asset Drops	EV / EBITDA
NRG Yield Drop #1	10.0x
NRG Yield Drop #2	10.0x
Remaining NYLD Drops	11.0x
NEP ROFO Drops	11.0x
Remaining NEP Drops	9.0x
Abengoa Yield Drop #1	11.3x

NRG Yield Drop #1 is actual; all others are UBSe.

Source: Company Filings and UBS Estimates

ROFO Roadmap Clarity

NRG Yield announced with 2Q14 results the composition of its second ROFO package which includes the Walnut Creek 500MW CCGT as well as 285MW of EME Wind (Tapestry and Laredo Ridge) with $120Mn of EBITDA guidance and $35Mn of CAFD. We present our analysis on the subsequent page with a contemplated 10x EV / EBITDA multiple, in-line with the actual multiple for the first drop which contained El Segundo (first ROFO drop analysis reproduced below). While Walnut Creek has ~one year less of contract life which supports the argument for a lower multiple, this package contains a much larger renewable component (285MW of wind versus 40MW of solar), thereby pulling the multiple back towards 10x.

UBSe EV / EBITDA Multiples:
ROFO Package 2: 10x
Remaining Assets: 11x
Average: 10.6x

1st ROFO drop sets a 10x EV / EBITDA expectation for limited life asset drop-down multiple.

Including Walnut Creek in the next ROFO package was expected as it allows NRG to preserve the contract life. Walnut Creek is dilutive to the weighted average contract life given its ten-year PPA and we did not believe management will be willing to put an asset into NYLD with a contract life far below ten years with ~eight likely being the minimum acceptable threshold. As of the Alta Wind S-1 filing (as of 6/30) the total weighted average contract life was 17 years with the solar portfolio having a 29 year weighted average expected life. Walnut Creek's current remaining life is now closer to eight years.

2nd '14 ROFO is ~worth $1/sh to base value; balance of pipeline worth ~$10/sh: All included in our valuation.

Figure 154: Analysis of NRG's First Dropdown

NRG ROFO Asset Drop #1:			
		Run-Rate EBITDA	Run-Rate CAFD
UBSe		102	29
Guidance		100	30
Purchase Price ($Mn)			
	Total	Cash	Project Debt
	1,021	364	657
EV/EBITDA		10.0x	
CAFD Yield		8.0%	
2014 ROFO CAFD Guidance			55
Defecit Following CVSR Deferral			25
2014 'Replacement Assets'			
Walnut Creek			*15*
Tapestry and Lardeo Ridge			*20*
Over/(Under) Guidance			*10*
Remaining EME 'NYLD Eligible' CAFD			$25-$35

Source: Company Filings and UBS Estimates

The New Norm: Employing Holding Company Leverage?

In the following tables we walk through the drop-downs and with a 10x EV / EBITDA drop-down multiple we estimate a $530Mn purchase price for NRG Yield to finance. With the CAFD of $35Mn we see latitude for management to add ~$115Mn of additional corporate debt; however, the Corporate Debt / EBITDA post the Alta transaction is 3.29x, above the target of 3.25x. We see management using this leeway, which would temporarily push the corporate debt / EBITDA to 3.7x (subsequently lowered by the next ROFO drops). Of the $428Mn in equity financing, we assume that management will opt to utilize the $188Mn of excess cash from recent equity and debt issuances (leaving the $87Mn of unrestricted cash and equivalents untapped). This financing decision prevents ~$2/sh of value dilution (further information on sensitivities are included with the valuation section).

Mgmt's target of 3.25x Corporate Debt / EBITDA drives our deal financing assumptions.

Use of $188Mn excess cash prevents $2/sh of dilution.

Figure 155: NRG 2nd Proposed ROFO Drop-Down

NRG ROFO Asset Drop #2: ($Mn)	
EBITDA and CAFD Guidance	
Run-Rate EBITDA	120
Run-Rate CAFD	35
Project Debt (as of 6/30)	
Walnut Creek	409
Tapestry	196
Laredo Ridge	67
Total Debt	672
EV / EBITDA (UBSe)	10.0x
Implied Purchase Price	528
Debt Financing (Targeting 3.25x Corp Debt/EBITDA)	100
Equity Financing	428
Gross CAFD Yield	8.2%
Total Debt / EBITDA	6.4x

ProForma Financing	Pre-ROFO 2	Post-ROFO 2
Corporate Debt	845	945
Corporate EBITDA (CAFD)	257	257
Corporate Debt / EBITDA	3.29x	3.68x
ROFO Drop 2		
Corporate Debt Latitude	114	
Corporate EBITDA (CAFD)	35	
Corp. Debt / EBITDA Target	3.25x	
Financing at Target Mix	1,200	
Project Debt Assumed	672	Adjustment
Corporate Debt Issued	100	14
Equity Issuance	428	

Source: Company Filings and UBS Estimates

Figure 156: Balance of NRG Proposed ROFO Drop-Downs

Remaining NRG ROFO Asset Drops: ($Mn)	
EBITDA and CAFD Guidance	
Run-Rate EBITDA	218
Run-Rate CAFD	101
Project Debt (as of 6/30)	
EME Wind (Viento+High Lonesome)	260
CVSR+Agua Caliente	907
Ivanpah	596
Total Debt	1,763
EV / EBITDA (UBSe)	11.0x
Implied Purchase Price	634
Debt Financing (Targeting 3.25x Corp Debt/EBITDA)	218
Equity Financing	416
Gross CAFD Yield	24.3%
Total Debt / EBITDA	9.1x

ProForma Financing	Pre-Drop 3	Post-Drop 3
Corporate Debt	945	1,163
Corporate EBITDA (CAFD)	257	358
Corporate Debt / EBITDA	3.68x	3.25x
ROFO Drop 3+		
Corporate Debt Latitude	328	
Corporate EBITDA (CAFD)	101	
Corp. Debt / EBITDA Target	3.25x	
Financing at Target Mix	2,397	
Project Debt Assumed	1,763	Adjustment
Corporate Debt Issued	218	110
Equity Issuance	416	

Source: Company Filings and UBS Estimates

The balance of the ROFO assets will likely be dropped at a higher multiple given the 20+ year contract lives – we use an 11x EV / EBITDA multiple. The remaining assets have an implied 24%+ gross CAFD yield which supports the argument that management may opt not to utilize as much corporate debt to finance the transaction but even without debt, the gross yield would be ~16%. We estimate

$220Mn of corporate debt will be utilized for the remaining ROFO assets, capping the debt issuance at a project level of ~9.0x total debt / EBITDA level. This is consistent with management's financing of the Alta Wind deal where NYLD issued $500Mn of corporate "green bonds" to arrive at a mid-9x metric (see right).

Delineating the Drop-Down Timeline

Below we present our latest timeline expectations for NRG Energy drop-downs into NRG Yield. We remain guided by management's stated dividend policy and the practice of 'best-in-class' MLPs that we expect YieldCos to emulate. Management's implied minimum ~4% annual dividend growth lends credence to our belief that management will continue to take a measured approach to dropdowns and will likely stagger drop-downs to keep the growth story intact (similar to the approach seen with an MLP), thus explaining our assumed timeline. We would not be surprised to see management split-out the remaining EME Wind assets but now that we include all assets in our valuation, an acceleration would be largely value-neutral to our price target.

Expect NRG Yield to split-up the EME wind drops to 'smooth' the drops given their smaller size relative to the large utility scale solar projects in the pipeline.

Figure 157: Updated Estimated NYLD Drop-Down Schedule

NYLD Estimated Drop-Down Schedule by Asset	Date	Run-Rate Adj EBITDA	Run-Rate CAFD
El Segundo - 2014 *DROPPED 6/30*	June 2014	94	26
TA High Desert - 2014 *DROPPED 6/30*	June 2014	4	1
RE Kansas South - 2014 *DROPPED 6/30*	June 2014	4	1
Remaining CVSR Ownership - 2014	June 2015	52	26
Ivanpah - 2015+	April 2016	68	28
Agua Caliente - 2015+	July 2015	43	17
Walnut Creek	October 2014	84	15
EME Wind - Tapestry and Laredo Wind	October 2014	36	20
EME Wind - Viento, High Lonesome, etc.	July 2017	65	30

Source: Company Filings and UBS Estimates (Illustratively keeping CVSR in this bucket for guidance alignment)

Solar Distributed Generation (DG) a large unknown

Big Opportunity ahead: The Convergence of Solar & Retail Industries

We are curious to see how meaningful of a business NRG Energy can leverage from its existing retail portfolio into a channel to sell solar products and anticipate management providing at least initial financial magnitude with 3Q14 earnings in November. In particular, we flag its Green Mountain product among its other offerings as a key focus for sourcing new customers. With the 'cost of acquiring' customers increasingly a concern, we see the convergence of the retail and solar sectors as taking place at a faster rate than we had thought. States likely to see this transition happen include those with higher residential rates, making New York, New Jersey, and even New England among the states with greatest interest. Rather, we see this tactical ability to drive customer growth in a cheaper way, leveraging both their current customer base and channels to acquire customers, as providing a meaningful head start vs. solar peers in the race to attract solar customers. All this being said, with the bulk of NRG's customer base located in Texas, we see low prices in the state as limiting the ability for solar compete. The Dominion electric transaction added ~500,000 customers (post attrition expectations) and NRG sees itself as offering rooftop solar "seamlessly" to its three million conventional retail customers.

NRG's retail footprint leaves it well positioned to capture solar opportunities.

Focus on the "New" states.

NRG elaborated on potential opportunities here where it sees tremendous potential value from establishing rooftop solar relationships which can last ~20 years versus less than five for traditional retail customers.

Retail conversion to solar is a new phenomenon given economics 'work' in NJ

Transitioning from Summer to Fall – with valuations declining across the board

Shine has come off some of the YieldCos as novelty wears off.

The excitement around YieldCos has cooled along with the summer weather with NRG Yield down 8% in the past three months. NRG Yield shares looked to as if they were fully reflecting the full ROFO pipeline in August but have declined back below $50. TerraForm Power had an IPO price of $25 and quickly surged out of the gates to $30+ but has stumbled down to $27. Late last month SunEdison announced that it would be pursuing a second YieldCo with an international focus to help the company monetize its foreign assets. NextEra Energy Partners and Pattern Energy Group are the only other two YieldCos we track with positive results over the period (NEP had its IPO in June). Factoring in PEGI's improvement and NYLD's recent struggles, Pattern has taken the crown of best performing YieldCo recently. Abengoa Yield also surged out of the gates follow its IPO but now is underperforming by 10%

PEGI is now the best performing YieldCo in the past six months.

What do we think of YieldCo's Outlook from here? Still some spots of sun.

- **More third-party acquisitions:** we think the bias remains to consolidate rather than IPO on their own, particularly as asset quality continues to decline with future portfolios.
- **What about growth rates?** Actually set to be *increased*. We think NEP will prove the most defensive in the sector, as it is poised to raise expectations with 3Q around its growth rate. Addressing long-term growth, we flag that PEGI recently expanded the size of its ROFO portfolio.
- **Adding DG solar into the mix?** Further inspiring valuation confidence will be a focus with NRG around integrating its future retail solar opportunities into the NYLD drop-down story. While we suspect long-term organic growth opportunities remain problematic for the entity, shares could yet see support in the medium term.

Figure 158: YieldCo Relative Performance Last Six Months

Source: FactSet

PG&E Corporation (Neutral; $46 PT)

In-line outcome with unusual 3Q impact from GRC rate increase

But San Bruno, GT&S ratecase, and Ex-parte revelations continue to take focus

We expect PCG to report 3Q **$1.09** vs consensus $1.10, with a fairly significant impact from the $453M GRC rate increase. We estimate a total $+0.23 increase, including 75% of +$0.18 from the $1.5B increase in ratebase (at 52% equity, 10.4% ROE), with 75% of the increase hitting 3Q and the remaining 25% incremental impact in 4Q. Another $0.09 of the impact is from deferred spending recovery from 1H14 (the increase is retroactive to Jan 1). We estimate that gas transmission revenues are about +$0.07 higher in 2014 vs last year due to the drought condition which drives up gas-fired generation capacity factors (+$0.02 for 3Q). Management guidance is for a combination of higher gas transmission earnings and "a few cents" of proceeds from the sale of SolarCity holdings should offset roughly -$0.10 of underearning at the gas transmission and storage utility. Dilution from shares reduces by -$0.04, but we note that this only accounts for the $800M-$1B of equity management plans to issue this year to fund the capital program, and not the extra $1.1B we expect to see from San Bruno penalties (based on the PD, which has yet to be modified and finalized).

Figure 159: PCG 3Q Walk

3Q14 Earnings Walk		EPS
3Q13 From EPS From Ops	**$**	**0.88**
Increase in rate base earnings		0.01
Increase in shares outstanding		(0.04)
GRC increase		0.14
Timing of 2014 GRC Recovery		0.09
Gas Transmission		0.02
Miscellaneous		0.00
Plant Incremental Work GT&S		0.00
3Q14 Non-GAAP	**$**	**1.09**
Consensus	*$*	*1.10*
2014 Guidance		*N/A*

Source: Company filings and UBS estimates, FactSet

GT&S ratecase suspended after ALJ removed following ex-parte revelations

With the GT&S case schedule now suspended (and the Administrative Law Judge reassigned) in the wake of the recent ex-parte communication revelations, even the previous 1H15 expectation for completing that case is now uncertain. We do not expect any 2014 or 2015 guidance nor any dividend growth decisions until after both the GT&S ratecase and San Bruno are resolved.

San Bruno process proceeding for now….

For the San Bruno OII penalty, parties recently filed their administrative appeals, setting the stage for what will almost surely be a follow-on legal battle in state and federal courts that could last years. Commissioners Florio and Picker have both asked for a review of the proposed penalty, while Commissioner Sandoval has asked for a greater penalty. For further information on the Sept PD and it's potential $4.75B impact on PCG (including loss of tax deductions and shareholder-funded safety spending already accomplished), please see our **9/2 note "Slammed and Dunked"**.

Loss of Peevey arguably the largest negative development for investors, but Picker is a positive one

While Peevey's departure will be viewed negatively by investors, we view the presence of Commissioner Picker as a particularly positive and level-headed influence at a time when the CPUC arguably needs a steady hand at the helm.

Chairman Michael Peevey announced that he will not be seeking another term as Chairman of the California Public Utilities Commission (CPUC). The current term expires at the end of this year, but Peevey will continue to serve for up to an additional year while a replacement is found and confirmed by state legislators. While not a surprise, the timing of the announcement is a bit earlier than expected and comes in the aftermath of PCG's self-reporting of unreported ex-parte emails between Peevey and PCG VP Brian Cherry. Among other disclosures, the emails revealed Cherry's assessment that Peevey had solicited from PCG, EIX, and SRE significant funding (~$1M-$50M each) to oppose California climate change initiative AB 32 and another $100k each for the CPUC's 100th anniversary celebration and other events. Peevey has generally been considered to be a moderating influence favorable to investment in the state through several periods of uncertainty and crisis in the state, including the 2001 California energy crisis and the more recent 2010 gas line explosion in San Bruno. While his departure will be viewed negatively by investors, we view the presence of Commissioner Picker as a particularly positive and level-headed influence at a time when the CPUC arguably needs a steady hand at the helm.

Furthermore, the most recent batch of email disclosure from PCG includes several from Commissioner Michel Florio regarding gas operating pressure in San Carlos also appear to imply that Florio was an advocate for PCG on this issue In Dec 2013, he wrote to Cherry, "Amazing how I've become "an apologist for PG&E" in just three short years, isn't it? THANKS, Mike"

Peevey's announcement also follows announcements this month from both the US Attorney General (AG) and the California AG that they would both be opening separate investigations into these late-disclosed ex-parte communications between the company and the CPUC.

US AG investigation continues into NTSB and Pipeline Safety Act matters

On Sept 22, a status hearing was held for the US Attorney's July 30th superseding indictment charging PG&E with obstruction of the NTSB investigation and 27 counts of violating the Pipeline Safety Act. Each of the 27 counts could result in$500K potential penalties (low end) that would equal $13.5M total plus double the greater of $281M gains made from the criminal behavior or double the vicitims' losses, which are cited at $565M. This would suggest that the total criminal penalties could soar to $1.12B. The company states that based on the evidence seen, none of the charges or fines are warranted.

Previously management characterized a superseding indictment as unlikely given the high burden of proof that employees deliberately violated the law.

Management adamantly states that the charges are without merit and that in any case, the outcome will not affect the company's ability to run a utility franchise. The federal case could last as long as 1-2 years or more to play out. Furthermore, the company believes that the case outcome will have no effect on the IRS interpretation of the tax-deductibility of any forthcoming California penalties.

For further details on the criminal indictment please refer to our note from March, 'The Next Shoe Drops'.

Raising our estimates for lower equity issuances in later years, remain below consensus

Our current estimates assume the company earns its authorized 10.49% (blended CPUC & FERC jurisdictions) in 2016. We emphasize that there is risk surrounding that assumption as the utility will file its next full cost of capital application in April 2015 for the 2016 test year.

We emphasize that risk surrounding the ROE assumption as the utility will file its next full cost of capital application in April 2015 for the 2016 test year.

While we believe the recent GRC order was relatively favorable for the company (especially in the context of the political atmosphere), **we remain somewhat cautious** on the outcome of the large and contentious Gas Transmission and Storage ratecase now in process with a suspended schedule that had called for an early-mid 2015 outcome (retroactive to Jan 1, 2015). We also assume a large secondary equity issuance of at least $850M this year (beyond the $800M-$900M for normal capital spending) as a result of San Bruno penalties. Should the San Bruno case take longer to generate a final order, this equity would push out to 2015. We have reduced our equity issuance assumptions for 2016-2018 based on our refined assessment of balance sheet needs for 52% of incremental ratebase funded with a combination of retained earnings (post-dividend), secondary equity, and debt. This is the primary reason for the increases in our 2016-2018 estimates. Our PT remains unchanged at $46, although we now apply a 5% discount to the

average utility peer 2016E P/E to reflect the increased regulatory risk surrounding the GT&S case as well as the San Bruno outcome in light of the ex-parte revelations.

For more information on the outcome of the GRC as well as the San Bruno penalty phase and the GT&S ratecase, see our recent notes: 9/2 "Slammed and Dunked" and 8/4 "Big Decisions Coming Soon".

Figure 160: PCG Mini-Model – Maximum Ratebase Earnings vs UBSe, 2014E-2018E

PG&E Mini-model	**2014**	**2015**	**2016**	**2017**	**2018**
CAPEX	5.3	5.0	5.1	5.3	5.3
Weighted Average Ratebase	28.0	31.0	33.5	35.5	37.8
Disallowed PSEP in SB ruling	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
Disallowed GT&S ratebase	-	(0.2)	(0.2)	(0.2)	(0.2)
FERC ratebase	*4.7*	*5.2*	*5.7*	*6.2*	*6.6*
CPUC elec ratebase	*20.3*	*22.2*	*23.6*	*24.8*	*26.4*
CPUC gas ratebase	*2.8*	*3.1*	*3.8*	*4.1*	*4.4*
FERC allowed ROE	10.90%	10.90%	10.90%	10.90%	10.90%
CPUC allowed ROE	10.40%	10.40%	10.40%	10.40%	10.40%
Blended allowed ROE	10.48%	10.49%	10.49%	10.49%	10.49%
Auth Equity Ratio	52%	52%	52%	52%	52%
MAX ratebase earnings ($B)	1.5	1.7	1.8	1.9	2.0
Shares - yearend	501	521	535	541	550
Shares - avg	479	511	528	538	546
Equity issued ($M)	1,810	1,050	600	300	400
MAX Utility EPS	3.16	3.26	3.41	3.55	3.73
Sale of Solar City stock	0.03	0.02			
Parent EPS	($0.12)	($0.08)	($0.10)	($0.12)	($0.13)
MAX PCG EPS	**3.06**	**3.19**	**3.31**	**3.43**	**3.61**
Growth		**4.3%**	**3.8%**	**3.5%**	**5.1%**
Consensus	***3.02***	***3.16***	***3.33***	***3.63***	
EPS in model	**3.07**	**3.17**	**3.29**	**3.42**	**3.60**
ROE in model	10.46%	10.48%	10.45%	10.45%	10.45%
Prior Estimates	$3.07	$3.14	$3.24	$3.28	$3.34

Source: Company filings, UBS estimates, FactSet

Figure 161: PCG valuation on 2016 average peer P/E multiple; no change to $46 PT

UBS Price Target		
EPS - 2016E	$	3.29
Group P/E		14.8
Discount		(5.0%)
Price Target		**$46.24**

Source: UBS estimates, FactSet

Pinnacle West Capital Co. (Buy; $60 PT)

A Nickel miss on mild weather

We expect PNW to report 3Q **$2.11** vs consensus $2.17, with mild weather (especially August) reducing EPS by -$0.06 vs normal (although 3Q13 was also mild, with the net effect of -$0.02 yoy). Sales growth (weather norm) of 0.5% adds +$0.02, while the LFCR mechanism helps another +$0.02. O&M savings of +$0.06 is largely offset by higher D&A, interest expense, and other taxes. Transmission rates add +$0.03, while the AZ Sun program increases +$0.03 as well (largely from the Gila Bend contribution).

We reiterate our constructive view on shares following the latest primary election results for the Arizona Corporation Commission (ACC), emphasizing a litany of positive potential catalysts into year end.

Figure 162: PNW 3Q Walk

3Q14 Earnings Walk	EPS
Reported 3Q13 Adj. EPS	**$2.04**
Normal Weather	$0.04
Normalized 3Q13 EPS	**$2.08**
Weather vs. Norm	($0.06)
Weather norm sales growth 0.5%	$0.02
LFCR	$0.02
D&A	($0.03)
Interest Expense	($0.02)
O&M	$0.06
Other taxes	($0.01)
Transmission TCA	$0.03
AZ Sun (including Gila Bend)	$0.03
Other, net	$0.00
UBSe 3Q14 Adj. EPS	**$2.11**
Consensus	$2.17
2014 Guidance	$3.60-3.75

Source: Company filings, UBS estimates, FactSet

PNW may initiate 2015 guidance on the call or EEI, but it is our understanding this is still under debate at the company. Our estimate remains $3.87 vs consensus $3.86. The usual O&M and load forecast updates will come with the 3Q release, although as usual, a new capex forecast isn't expected until February with the 4Q release.

We expect to see the latest solar rooftop install statistics filed this week by the company. Management has indicated that growth is still robust and that the $5/mo net metering fee is apparently not having much of an effect.

Lots of (positive) regulatory datapoints into year-end for PNW

We reiterate our constructive view on shares following the latest primary election results for the Arizona Corporation Commission (ACC), emphasizing a litany of positive potential catalysts into year end. Specifically, we expect a (favorable) decision from the ACC on APS' purchase of Four Corners in the next few weeks. We also look for constructive developments on APS' proposed Ocotillo peaker in downtown Tempe (estimated at $600-700 Mn), with '16 construction and 2018 in-service; the plant recently passed the citing committee. Lastly, we see APS' latest solar RFP for an addt'l 20 MW of solar (either utility-scale or under its novel utility-owned DG program), at a cost of ~$60-70 Mn as also on deck, seeing both ACC commissioner Brenda Burns and Gary Pierce as eager to finalize pending dockets prior to their term expiration at yr-end.

ACC opens rate design procedural docket, in attempt to re-hash solar pre-case

On Sept 11, the ACC opened a generic docket (AU-00000C-14-0329) to develop procedures to study and consider rate design options for electric and gas utilities. At this early stage, the docket will merely consider whether rate design should be considered as part of the general rate case process or if it should be considered separately ahead of the case (separating would avoid risk of a protracted case). The focus on rate design is deliberately broader than net metering, opening the possibility of remedies such as higher fixed demand & solar charges (~$4.90/mo for avg. system).

… But new blood at the ACC limits real progress for now

While we expect a staff opinion filing by early October followed by a few weeks for stakeholder comments and ACC hearings, we remain cautious on any tangible progress ahead of the two new ACC commissioners next year. The real question is how much of the net metering discussion can be hashed prior to the next rate case in mid-'16.

For further details on Arizona, please see our 8/1 note "Taking the Solar Concerns Head On" and our 8/27 note "Primary Night Takes: Finding Shade in Arizona".

New deal would keep rates competitive despite SCR build

Meanwhile, the company announced an environmental compliance proposal this month to shut down Cholla Unit 2 and cease burning coal at Units 1 and 3. If approved by the EPA, the plan would save $350M, about the same amount to be spent on SCRs for Four Corners in 2016/17. We emphasize an added focus on customer affordability as regional utilities attempt to limit attractiveness of distributed solar solutions against higher retail rates.

Palo Verde lease expiration provides 1x benefit

With the sale-leaseback of Palo Verde resetting in 2016, payments are expected to drop from $49M to $23M, although rates aren't expected to change and catch up until 2017 under the latest ratecase filing plan. We expect the $26M benefit to be essentially a 1x item in 2016.

Arizona expected to get serious about net metering reform with new regulators

The focus on rate design in AZ is deliberately broader than net metering, opening the possibility of remedies such as fixed demand charges.

We don't expect any solar policy tariff changes until new rates in 2017

It appears to us that the $4.90/month fixed charge currently applied to new customers opting for solar rooftop installations is unlikely to change prior to 2017 under new rates in a general rate case. Rather, once the procedures are agreed upon, we expect the ACC to open a generic proceeding to review what a fair rate design and compensatory regime for solar should be, with the outcome then applied concurrently with new rates in 2017. While we flag the commission had seemingly been in favor of a higher fixed charge initially (around ~$20/mo. on the advice of RUCO, which had advocated this level as its initial 'cost shift' burden—and hence the short turn around on a subsequent rate case), we see the utility as willing to live under the current construct given the added certainty with its existing construct. As a reminder, APS does not benefit from the $5/mo. Payment,

as this simply nets against payments made to the utility under the LFCR (which is designed to partially make up for the effects of EE and DG).

Initial look at projections? 'pre-filing' of next rate cases parameters expected through the generic docket

APS has agreed to submit a significant data filing in support of the procedural docket, which will essentially be a 9-month preview of their ratecase filing, which is expected to come in 2H-2015. The data filing presumably would include an early look at projected load growth, a hot button issue for investors.

Higher fixed charges and a new rate design are all possible now

A central tenant to the next rate case will be the meshing of rate design with rate compensation to offset lost sales from energy efficiency and distributed generation sales. It's unclear whether APS' existing LFCR mechanism will remain in place (partial decoupling), which could yet be replaced/traded for a much more robust compensation structure including meaningfully higher demand charges/fixed charges on customers who opt to shop. Regardless, we see the rate design principles to be crafted in the next year as central to establishing a baseline on which the fate of its riders will be established. Ultimately, we think the commission will be open to settlement in the case, particularly with rate design addressed ahead of time, enabling a consistent return profile.

Ratebase solar rooftop pilot moving through regulatory considerations

Should the ratebase solar pilot be utility-scale solar or DG rooftop?

APS' proposed 20MW, ~$65Mn pilot to install ratebased rooftop solar (see below for more details) was kept under consideration after motions to kill the program were dismissed at a Sept 6th procedural hearing. An ACC staff recommendation is expected by the end of October, with commissioners taking up the issue in Oct/Nov. Among the issues being considered are whether the state needs these 20 MW of solar at all, and if needed, should it be utility-scale solar or DG rooftop (utility economics are agnostic on that last point).

Ratebase rooftop solar: not really a game changer

While we see the proposal as an important step, enabling the company to go on the offensive against the effects of DG, it remains to be seen how competitive the company's offering will be versus peers. Criteria include that the (1) customer cannot qualify for a traditional leasing programs (so it will not compete head to head), and (2) roofs are biased towards south/west, with a targeted focus on householders within more specific reliability regions. The program is designed to facilitate solar on lower income customer's roofs, with a fixed monthly discount on consumer bills for allowing APS to install panels on customers' roofs. Importantly, the 20MW, ~$65Mn pilot helps drive more local support from solar developers, as the company seeks to outsource the work to these builders. The company is looking for approval in September, for implementation in December. For further details please consults our 2Q14 earnings note.

APS has proposed both a utility-scale and distributed solution – agnostic on either

Ultimately, we see APS as agnostic to either its utility-scale 20MW solution at the Redhawk CCGT in the desert, or its more novel distributed solution. While it's a bit odd to us of comparable cost (~$3,250/kW), we see the bigger issue as being whether the ACC determines there is need for the capacity to fulfil its obligations. The doubt relates to the current penetration of DG in the state, which is ahead of

the targets, as well as projected load growth statistics for the state. Net-net, we're biased to think it still gets approved, as incremental projects are layered in.

Solar interests take hit in ACC Republican primary

Solar interests are not supporting Democratic opposition in this November's ACC elections

In August primary elections, Tom Forese and Doug Little won the Republican primary for Arizona Corporation Commissioners. The two beat out the Solar industry's preferred candidates Lucy Mason/Vernon Parker after a very contentious campaign that press reports say went so far as to include Little raising money for dog rescue groups at campaign events after being called a "lap dog" for APS by solar groups (we disagree with this characterization). We see the primary outcome as among the more constructive data points for shares of late, enabling a clearer run way through 2017. We reiterate our Buy, and believe shares could rally relative to peers in the coming months on the back of the recent slate of good news.

Another significant victory for PNW after recently winning a GRC filing delay

We expect the win to keep the ACC generally supportive of APS and investor concerns in the coming rate design proceedings as well as the next general ratecase filing in 2016.

We expect the win to keep the ACC generally supportive of APS and investor concerns in the coming rate design proceedings as well as the next general ratecase filing in 2016. After recently winning a delay from the ACC in its requirement to file a ratecase back to 2016, this stabilization of the ACC is a significant victory for the company and should ultimately lead to actions to correct the sales erosion and revenue loss from solar rooftop conversions and energy efficiency. Opponents Mason/Parker had run opposing a proposed property tax on leased rooftop solar installations, which still appears to be dead for now in the state legislature. While its possible for the ACC to consider raising the existing $4.90/mo net metering fee on solar rooftops – perhaps to the $20 that had been supported by RUCO – we believe that no changes will be made while broader rate design issues are being considered. This is not likely to take place until 2017 earliest (after the conclusion of the ratecase), and could be completely moot depending on the outcome of rate design reforms and the rate case. More generally speaking, the race in AZ is also indicative of other recent races in which solar and utility advocates increasingly square off in the political arena over net metering subsidies.

Customer growth remains an important offset to reduced usage

We emphasize that customer growth remains center stage, with ratebase growth enabled through the addition of new capital to serve customers through distribution investment, rather than through load-growth. As such, we see the +1.4% YTD customer growth (FY14 guidance is +2%) trend as a meaningful constructive underlying datapoint to offset the negative recent normalized sales trends. At the same time, Homebuilders continue to note an interest in multifamily homes, rather than more costly/energy-intensive single family-homes as the default for new buyers in this market. For further details on weather-normalized load growth trends nationally and in Pinnacle's service territory, please refer to our 8/13/14 note 'The Economic Recovery Sputters Along'.

Growth potential from transmission JV

New transmission JV could see its first project win in mid-2015 from the CAISO solicitation.

We see the transmission joint-venture with Berkshire Hathaway's subsidiary MidAmerican Transmission as another potential avenue of growth for PNW. Under its subsidiary Bright Canyon Energy, PNW is along with its partner looking at several opportunities in the West. The JV notably plans to participate in the bidding

of the DCR line, recently approved by the CAISO Board. The bidding process will be initiated in August, with a winner selected by mid-2015.

More beyond just this line? APS and AZ have initial interest in joining Western grid

We expect PNW to pursue similar opportunities in the future, and see it as an interesting way to potentially boost growth beyond the utility distribution business in AZ. We emphasize that partnering with MidAmerican Energy in the West is a particularly attractive move for APS, seeing numerous potential investment opportunities following the acquisition of NV Energy and given the pending implementation (and likely widening) of the CAISO's Western Energy Imbalance Market (EIM). We flag that joining the EIM for Nevada appears to have been a pre-condition to the NVE acquisition, and recently note a more receptive attitude from PNW to the concept of the EIM. It appears the ACC's concerns are more oriented towards the cost of EIM implementation, rather than underlying jurisdictional concerns of associating with the CAISO (and potential for FERC intervention).

Phoenix outlook continues to improve although modestly: but *where's* the normalized utility sales growth though?

Mgmt. continues to be optimistic about the local economy and job growth coming from local business leaders across the state. While the improvement is a bit less robust than previously contemplated, the question remains to what extent homes and population growth will translate into new customers and aggregate sales growth. We flag the -2.0% decline in normalized sales is bit distressing, but don't see a single quarter as a trend. Rather, we look towards the balance of the year for a better view on trends in the economy. We flag that broader trends on residential and commercial sales appear to be lagging expectations nationally in 2Q, with industrial offsetting sales losses in some jurisdictions (albeit not APS).

Management's projections remain +2.5% retail customer growth from 2014-2016 and +1.0% for 2014-2016 sales growth when netting out the impact of energy efficiency and distributed generation from existing customers.

Four Corners: expect decision in next few weeks

After direct and rebuttal testimony concluded in June and July, and hearings in August, a final decision on the revenue requirement is expected in the next month or so, with rates in effect immediately following the decision. As we have mentioned previously, we don't see any issues here.

Adding to the opportunity set? Grid-scale storage

Following similar moves in California, it appears RUCO and APS are in discussions to develop a grid-scale storage proposal to develop MWs to effectively meet 'peak' load needs in lieu of additional peak capacity. While still preliminary, we think these investments would indeed be eligible for ratebasing, potentially additive to its current investment plan.

Does storage deal enable PNW to move forward with Ocotillo? Yes.

We read a recent filing between RUCO and APS on the subject of storage as simultaneously endorsing the company's plans to develop its Ocotillo peaker plant (5 CTs replacing existing units in urban Tempe). We continue to expect this plant will be approved by the ACC later this year, as part of the last few decisions by the still sitting commissioners (there will be two new ACC candidates taking their seats in January).

Ocotillo passes transmission line siting committee

The $600M-$700M modernization of the Ocotillo plant passed the transmission line siting committee in September. Construction is still expected to begin in 2016 to be completed by 2Q18. The upgrades will bring the size of the plant from 330 MW to 620 MW. While owners of gas-fired generation near Palo Verde have argued for their capacity as an alternative to the upgrade, PNW's argument in favor of Ocotillo continues to focus on its location within the Tempe load pocket.

Environmental compliance takes out Cholla Unit 2

On Sept 11, APS announced the closing of Cholla Unit 2 by April 2016 as part of a plan to comply with Regional Haze, BART, Mercury, and HAPs rules. Units 1 and 3 would also cease burning coal by the mid-2020s. If these proposals are accepted by the EPA, the company could save as much as $350M in emission control upgrades, roughly the same amount planned for the installation of SCRs on Four Corners 4 & 5 in 2016-17.

Asset sales: Arizona merchant market for sale?

Re-ratebasing merchant gas in AZ is upside for APS

We look for Sempra Energy to announce in coming months of its last merchant power plant sale in the state, Mesquite, as it seeks to fully divest its power exposure. We suspect Salt River Project (SRP) among other regional utilities could yet opt to purchase the plant (it bought the first units) amidst continued re-regulation of the merchant assets in the state. We suspect this could be a positive datapoint for shares, boding well for APS' comparable moves likely in 2015 or early 2016 associated with its next rate case filing (exit repurchase options are already embedded within certain of its existing PPAs which expire in coming years).

Consistent strategy with its pending acquisition of Four Corners coal stake

Valuation: Maintain Buy and $60 PT

We continue to value PNW at a 5% premium to the average 2016 utility PE multiple given the potential to see an acceleration in its earnings opportunity. We suspect that higher ratebase growth in later years might drive to lower end of guided ROE range.

Figure 163: ROE for APS using comparable calculation to PNW guidance

ROE Calculation	2013	2014	2015	2016	2017	2018
ROE Calcuation #1						
Net Income	425	440	456	494	521	563
Rate Base (From Presentation)	7,200	7,400	7,900	8,200	8,900	9,900
Equity Ratio (Wtd. Avg. FERC/ACC)	54.44%	54.4%	54.4%	54.4%	54.4%	54.4%
Equity	3,920	4,028	4,301	4,464	4,845	5,389
ROE (Rate Base Method)	**10.8%**	**10.9%**	**10.6%**	**11.1%**	**10.7%**	**10.5%**
ROE Calcuation #2						
Net Income (Same as Above)	425	440	456	494	521	563
Equity (GAAP @ APS)	4,309	4,532	4,760	5,300	5,554	5,836
Earned ROE	**10.1%**	**9.9%**	**9.8%**	**9.8%**	**9.6%**	**9.9%**
PER PNW	*Greater than 9.5% through 2015*					

Source: Company reports and UBS estimates

Our EPS estimates are below which reflects the expectation for a rate case filing in 2016, driving an increase in mid-2017E. Additionally, 2018 becomes the big 'bump' year, with our estimate at $4.56 quite conservative (no further acquisitions, accelerated spend, etc.).

Figure 164: PNW Estimates, 2013-2018E

	2013A	2014E	2015E	2016E	2017E	2018E
UBS estimates	$3.66	$3.75	$3.87	$4.00	$4.19	$4.56
Prior estimates	$3.66	$3.75	$3.87	$4.00	$4.19	$4.56
Guidance	$3.55 - $3.70	$3.60-$3.75				
Consensus	$3.66	$3.70	$3.86	$3.99	$4.03	

Source: UBS Estimates, company data, FactSet

Figure 165: UBS 2016E P/E Valuation

Price Target Valuation	
PNW 2016E EPS	$4.00
Regulated Utility Group P/E Multiple	14.4x
Premium	5%
Price Target	**$60.44**

Source: UBS Estimates, FactSet

PPL Corporation (Neutral; $36 PT)

Despite a potentially weak qtr vs. Street, we see clarification of its EPS growth rate to 4-6% as an offsetting factor – and positive factor into results

Supply declines leaves quarter in-line with consensus.

3Q results are likely to be relatively inline (**$0.55** vs Consensus of $0.55), as we *despite* Supply results to meaningfully decline YoY inline with its Full Year 2014 guidance. We note that YTD Supply has posted +$0.06 despite a FY14 guidance of $0.17 (following positive revisions already with 2Q), which implies a -$0.22 YoY guidance. This would imply a -$0.28 decline in 2H14. While 1Q results from the polar vortex has clearly put upward pressure on results within management's guidance range, we think the street's $0.55 consensus remains too high. Importantly, we don't see risk to 2014 guidance, with our estimate already below the midpoint of 2014.

Figure 166: 3Q14 Earnings Walk

3Q14 Earnings Walk	
3Q13	**0.66**
Earnings Drivers:	
PPL EU	0.02
(Weather - Unfavorable)	(0.01)
LG&E and KU	(0.01)
UK	0.01
Supply:	
Tax One-Time	0.04
East Margins	(0.06)
West Margins	(0.02)
Capacity	(0.07)
O&M, D&A, Other	(0.01)
Financing (Ironwood/Supply Debt)	0.01
Dilution	(0.01)
3Q14 Ongoing EPS	**0.55**
Consensus	0.55
UBS 2014e	2.31
2014 Guidance	2.20-2.40

Source: Company Filings, FactSet, and UBS Estimates

Links to our relevant recent research are below:

10/6/14 PPL Plus PEG: Weighing the Merits of a Bid
10/1/14 Is Coal in Maryland's Future?
8/18/14 Solving the Growth Equation through Cost Cuts
6/12/14 PPL Finds Itself Bejeweled

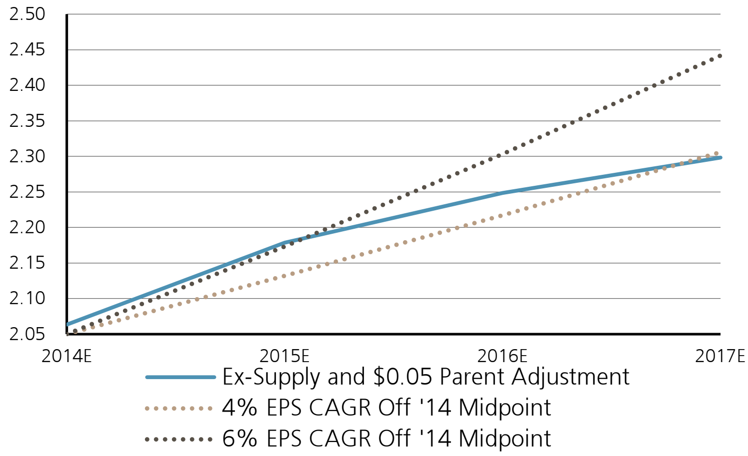
PPL likely to 'clarify' its growth rate: 4-6%, rather than 4%?

Expect management to more clearly definite its longer-term EPS growth target.

The company appears poised to clarify language of 'at least 4%' from the time of the announcement of its Talen spin, emphasizing a range likely closer to 4-6% (consistent with what its CEO would 'want to target' to be competitive with its peer group). Management made comments on this call and it is clear management does not intend to wait until the transaction is closed to address the growth rate. The more relevant question is how does management intend to achieve this

growth, as it previously emphasized ongoing efforts to limit the ‘dis-synergies’ of spinning off its generation segment (re-allocating SG&A); this remains a chief source of EPS upside in our estimates, with the base business achieving the lower end of its range on a ratebase basis itself (ratebase CAGR of ~7% is offset by one-time rate reset in UK). In focusing on the new UK RIIO rates, the key question will be to what extent the company can continue to out-perform on its targeted metrics to be awarded premiums (our estimates assuming a halving in 2017 as legacy DCPR revenues roll-off).

Figure 167: PPL Pro-Forma EPS Guidance vs UBSe



Source: Company Filings and UBS Estimates

PPL gets approval for the Montana hydro sale to NW Energy

Kavula dissents primarily on competitiveness on process

PPL and Northwestern Energy received approval on September 25th for their pending transaction, for the requested price of $870 Mn, with a corresponding revenue requirement of $116 Mn, predicated on a consistent 9.8% ROE. Commissioner Kavula dissented in part on the transaction, emphasizing in particular the competitive process was not sufficiently robust, noting that there is ability to export only ~half of the capacity to adjacent markets (Alberta under the new tie-line), as well as evaluating the merits of a further long-term PPA (in lieu of acquisition).

Good to get this out of way – but what to do with Colstrip now?

We view the deal getting done as a constructive datapoint for both companies – and now turn to the next question for PPL Supply/Talen: what to do with its last remaining asset in the state? Colstrip. While there remain lingering questions around compliance EPA regulations for the units, we suspect a number of regional utilities could yet move to acquire the assets, albeit at depressed valuations (particularly should pressures for Puget to divest its coal asset succeed in bringing this stake to market as well).

The Talen Divestment: Limited Set of Possible Participants

We see Calpine as likely bidder for at least Sapphire assets, if allowed under various market monitoring scenarios.

We see a limited number of participants who can potentially acquire the proposed 1.3GW of plant divestments following PPL’s proposed tie-up with Riverstone to create Talen Energy. While an initial run of the screen (limiting participants to 5GW of ownership under the ~Eastern PJM interconnection/ ie-‘5004/5005 interface’ in PJM lingo) would include Calpine (explicitly

mentioned), but exclude a number of other large regional players include NRG, EXC, and PEG.

We emphasize that a broader definition of market mitigation (~3% of total market ownership), would limit Calpine, among a host other generators (including Dynegy, pro-forma for its latest DUK/ECP acquisitions). We see Calpine as the most likely acquirer, behind other potential interested private equity investors, should the lower threshold for potential participants ultimately be approved. It remains unclear who else among strategics would have real interest (DYN appears to have its hands tied until at least mid-2015).

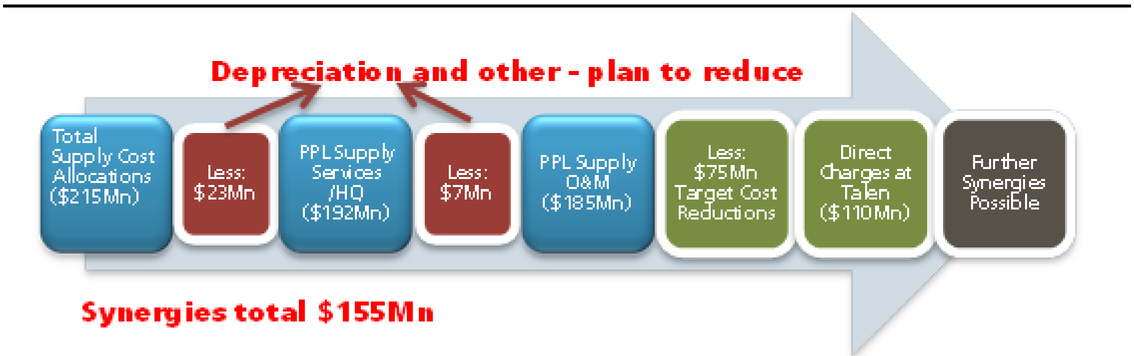
If not Calpine, we see these assets as ideally positioned to remain private – yet again – at a discounted cost.

The market monitor's comments appear to suggest that more 'operational' market mitigation efforts (rather than a greater quantity of MWs to be divested) would prove sufficient to address concerns, specifically requiring cost-based energy bids and participation in the regulation market to the same extent as previously committed (albeit unclear for what duration this would be required).

PPL continues to march forward with Talen spin

With 2Q14 results PPL management stated that it had made "nearly all" of the necessary regulatory filings and specified that it has completed the FERC, NRC, and PA PUC filings which leaves only the Department of Justice request which should be made in the upcoming few months. The deal is still expected to close in 1Q or 2Q15. Addressing the progress at a recent conference management left the target synergies unchanged and we would not anticipate any material revision ahead of the official Talen launch. CFO Vincent Sorgi commented that the $155Mn of synergies are "achievable".

Figure 7: PPL Corporation → Talen Synergy Waterfall (UBSe)



Source: Company Filings and UBS Estimates

Compass points towards late 2014/early 2015 for update on Compass

Management reiterated that it believes it will be in a better position by year-end (potentially EEI?) to provide an update on the regulatory process and timeline for the $4-6Bn Project Compass. Every $1Bn of spending at PPL Electric could contribute ~$0.08/sh to earnings and in the optimistic best case scenario where PPL gets approval for the project and secures all of the capex this could essentially double PPL-PA earnings but there are significant obstacles to such a scenario. We remain cautiously skeptical given the scale of the project and following AEP's unsuccessful Potomac-Appalachian Transmission Highlight (PATH).

3Q announcement might be too soon for a real update on the proposed Compass transmission project.

Susquehanna Unit 2 still continuing to frustrate investors

Susquehanna remains the focus for Talen operationally

Recently PPL said that it was "cautiously keeping an eye on [Susquehanna] Unit 2 and shut the Unit in September after the latest vibration monitoring equipment indicated that the turbine blades had cracks, with management indicating at that time the outage was unlikely to cause a material loss. The company still is planning on installing new, shorter blades (the type installed at Unit 1 earlier this year) at Unit 2 during the next maintenance outage in Spring 2015. Management commented that the new blades shorter blades have reduced the vibrations and cracking at Unit 1 but only made other modifications to Unit 2 recently. We value the pending Talen Energy spin at ~$3.50/sh in our PPL Corp. sum-of-the-parts analysis, of which approximately 1/4th relates to Susquehanna Unit 2.

Susquehanna issues put pressure to diversify

Given the timing of the Unit 2 maintenance outage, we could see this as an overhang on shares for a 1Q/2Q15 Talen launch seeing this as the single largest asset in the portfolio. We see continued issues at the plant as further bolstering arguments for Talen to pursue M&A to become larger – and dilute down its exposure to single concentrated assets.

In Search of a Direction in KY

PPL withdrew the application for the $700Mn CCGT but what is the solution in Kentucky?

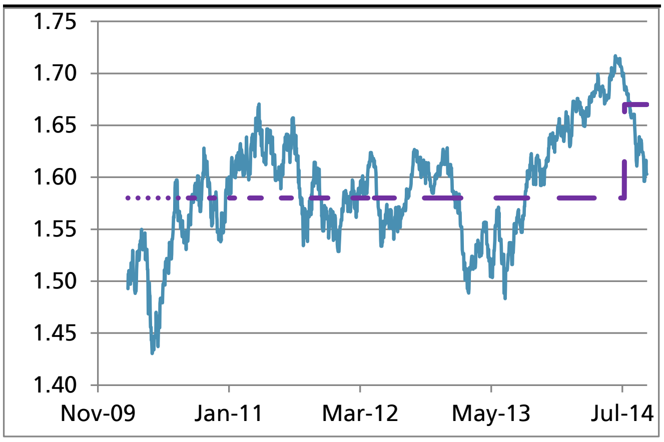
Following PPL's decision to not go ahead with the 700MW Green River CCGT in Kentucky, we look for management to discuss its proposed solution for the 150-300MW shortfall predicted over the next few years (likely a capacity solution) and what the plans are fo the segment which has one of the more challenging economies. While the $900Mn plant would have been a nice catalyst for the underperforming KY segment (potentially a ~$0.05-0.06/sh EPS uplift if approved), management has continued with its 10MW, $36Mn solar request with a 2016 COD.

Scotland votes 'No': GBP FX rate recovers slightly

Latest USD-GBP FX rate has declined $0.07 below PPL's guidance of $1.67.

After weeks of elevated debate, Scotland voted 'No' to independence from the United Kingdom with the final tally at 55% 'No' versus 45% for 'Yes'. While we anticipate continued debate on the political ramification and power shift between Scotland and the UK, the most relevant implications in our coverage universe are for PPL Corp which derives the majority of its pro-forma earnings from its UK regulated utilities. The Pound recovered some of its recent decline but is still well below the $1.70 level set in July. With the latest mark at $1.60, this is the lowest since November 2013 and will weigh on results in the critical post 2015 timeframe.

Figure 168: USD-to-GBP Exchange Rate (Late 2009-Present)



Source: FactSet and Company Filings

Figure 169: USD-to-GBP Exchange Rate (YTD)

Source: FactSet and Company Filings

As of 6/30 PPL was almost entirely hedged for 2014/2015 with 2016 55% hedged at $1.66. We look for an update on the 3Q14 earnings call/EEI on whether the latest political issues have impacted management's hedging strategy going forward.

Figure 170: PPL GBP-US Hedging

FX Hedging		
Year	Hedged %	FX Rate
2014	97%	1.59
2015	98%	1.63
2016	55%	1.66

Source: Company Filings

Figure 171: UK Regulated EPS Estimate Summary

UK Regulated Op EPS Guidance Midpoint				
	July 2013	*June 2014*	*July 2014*	*UBSe*
2014E	$1.29	$1.34	$1.35	$1.36
2015E	$1.25	$1.36	$1.36	$1.35
2016E	$1.25	$1.43*	$1.36	$1.38
**Assuming 5% growth off 2015E*				

Source: Company Filings and UBS Estimates

Our colleagues have also written on the latest economic outlook for the UK in our recent note '**UK Economic Perspectives - Taking Scotland Seriously**'.

Where are our estimates? Expect top end of guidance.

We're moving up our estimates a touch further to reflect both strong YTD results – and expectations for reasonable 3Q and 4Q results, towards the top end of its $2.20-2.40 EPS range.

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Figure 172: Updated PPL Estimates – Higher at Supply Following Recent Pricing Improvement

PPL EPS Estimates	2012A	2013A	2014E	2015E	2016E	2017E	2018E
Energy Supply	0.81	0.39	0.15	0.11	0.07	(0.04)	(0.00)
PA Electric Utility (PPLEU)	0.23	0.32	0.39	0.42	0.46	0.51	0.55
Total UK EPS (WPD/CN)	1.19	1.37	1.36	1.35	1.38	1.34	1.37
Kentucky Utilities	0.33	0.48	0.43	0.50	0.50	0.60	0.57
Corporate/Parent Plug	(0.14)	(0.11)	(0.02)	(0.04)	(0.05)	(0.10)	(0.15)
Total	2.42	2.45	2.31	2.34	2.37	2.31	2.34
Consolidated Guidance (Inc. Supply)			*2.20-2.40*				
PPL UK Guidance			*1.35*	*1.32-1.40*	*1.30-1.42*		
Ex-Supply and $0.05 Parent Adjustment			2.11	2.18	2.25	2.30	
Guidance (Ex-Supply)			*2.00-2.10*	*2.05-2.25*			
4% EPS CAGR Off '14 Midpoint			*2.05*	*2.13*	*2.22*	*2.31*	
6% EPS CAGR Off '14 Midpoint			*2.05*	*2.17*	*2.30*	*2.44*	
FFO (CFO pre-W/C) / Total D	17.3%	16.5%	16.9%	16.9%	16.7%	16.1%	13.9%
FFO (CFO pre-W/C) / Total D	26.3%	27.6%	18.4%	18.2%	17.6%	15.0%	15.8%
FFO (CFO pre-W/C) / Total D	15.3%	15.0%	16.6%	16.7%	16.5%	16.2%	13.7%
Previous UBSe	*2.44*	*2.45*	*2.26*	*2.34*	*2.37*	*2.31*	
Street Consensus			*2.27*	*2.27*	*2.27*	*2.27*	*2.27*
Avg. Shares O/S	582	649	654	654	654	654	654
UK Guidance Range		1.32	1.35	1.32-1.40	1.30-1.42		

Source: Company Filings, FactSet, and UBS Estimates

Price Target Unchanged at $36

We reflect our latest estimates [2014 revised up] and multiples to maintain our $36 price target. With shares cheap to our SOP, and with upside to 2014 guidance – and long-term EPS, we suspect shares could trade well into the quarter end.

The key question for both estimates and valuation remains to what extent PPL can reduce the legacy costs of the Supply spin.

We believe the stand-alone company will continue to garner increasing interest around its UK business, as the overall proportion grows ex-Supply – and with fewer developments elsewhere in the organization. The key question for this segment will be how (and if) management can offset the seeming roll-off of legacy DCPR5 bonus revenues in 2017 (management only provided guidance from 2014-16 at the time of the spin announcement.)

Figure 173: Updated SOP Valuation for PPL

All figures in US $ million except per share data	2016E	P/E and EV/EBITDA Multiple					Enterprise Value		
		Low	Peer	Prem/ Discount	Base	High	Low	Base	High
International (UK) Utilities	2016 Net Income			P/E Multiples				Equity Value	
WPD & Central Networks - P/E	905	*12.8x*	14.8x	-1.0x	*13.8x*	*14.8x*	$11,579	$12,483	$13,388
Implied Per Share	1.38						*$17.70*	*$19.09*	*$20.47*
Domestic Regulated Utilities	2016 Net Income			P/E Multiples				Equity Value	
PPL Electric Utilities (PA T&D)	303	14.8x	14.8x	1.0x	15.8x	16.8x	$4,486	$4,789	$5,093
Implied Per Share	0.46						*$6.86*	*$7.32*	*$7.79*
PPL Kentucky (KU/LG&E)	327	13.3x	14.8x	-0.5x	14.3x	15.3x	$4,352	$4,680	$5,007
Implied Per Share	0.50						*$6.65*	*$7.16*	*$7.66*
Domestic Utilities Equity Value using P/E	631	*14.0x*			*15.0x*	*16.0x*	$8,846	$9,476	$10,107
Implied Per Share	0.96						*$13.53*	*$14.49*	*$15.45*
Parent Interest Expense Drag	2016 Net Income			P/E Multiples				Equity Value	
Parent Debt + Supply Debt @ Parent	(61)	13.8x	14.8x	0.0x	14.8x	15.8x	-$840	-$901	-$962
Implied Per Share	(0.09)						*-$1.28*	*-$1.38*	*-$1.47*
Current Number of Shares outstanding			Shifting to P/E approach adds ~$1.30/sh				654	654	654
Total PPL Regulated Equity Value per Share (ex-Supply)							$29.75	$32.19	$34.44
				EV/EBITDA Multiples					
Talen Energy	2016 EBITDA		Peer	Premium	Base	High	Low	Base	High
PPL Supply	548	7.0x	8.0x	0.0x	8.0x	9.0x	$3,836	$4,384	$4,932
RJS (Riverstone)	169	7.0x	8.0x	0.0x	8.0x	9.0x	$1,182	$1,351	$1,519
Synergies (65% to PPL shareholders)	155	7.0x	8.0x	0.0x	8.0x	9.0x	$1,085	$1,240	$1,395
M&T (EnergyPlus)	25	4.0x	5.0x	0.0x	5.0x	6.0x	$100	$125	$150
Total Unregulated EV	897	6.9x	9.0x	0.0x	9.0x	8.9x	$6,202	$7,099	$7,996
Projected Talen									
PPL Supply								$2,713	
RJS								$1,250	
Cash and 2015 FCF for RJS								-$788	
Net Debt								$3,175	
Net Debt / EBITDA			Incremental ~$1/sh over PPL Supply					*3.5x*	
Total Equity Value							$3,027	$3,924	$4,820
Implied FCF Yield (EBITDA - Capex - Interest Exp, assuming no taxes)							11%	9%	7%
PPL Portion (65%)							$1,967	$2,550	$3,133
PPL Slice of Talen Energy (65%) per Share							$3.01	$3.90	$4.79
Grand Total PPL Equity Value per Share							$32.76	$36.09	$39.23

Source: Company reports and UBS estimates

Public Service [PSE&G] (Neutral; $40 PT)

Quarter could be ~8% light of consensus but highlights will be increasing FY14 guidance, more spending at LI, and comments on M&A reports.

Public Service Enterprise Group is forecasted to report 3Q14 adjusted EPS of **$0.72**, ~8% below consensus ($0.78) as the negative from lower capacity payments in the back-half of the year is too much for Power to overcome. The utility is expected to post flat results YoY as the positives from higher transmission spending and continued pension savings are offset by the ~20% decline in CDDs in the service territory that weighs on results. The biggest offset for Power is the decline in capacity payments to $166/MW-Day from $242/MW-Day which lowers earnings by $7Mn ($0.09/sh) for the 10.5GW fleet. Offsetting the capacity payment drag is the reversal of the impact of the 756MW Bethlehem Energy Center which was down for major maintenance in 3Q13 (5.6% and 34% capacity factors in September and October 2013, respectively) collectively accounts for $0.06 of O&M and forgone generation.

Negative drag from capacity payments is too much for PEG Power to overcome – we see a $0.04 YoY decline vs consensus of $0.02 improvement.

On July 30th with 2Q14 results management reaffirmed that it expects to be at the top-end of the $2.55-$2.75 guidance range even when considering weather through mid-July's forecasts. On September 3rd management again commented that it would be at the high-end of guidance and with September weather much closer to normal than July/August were, we have lowered our FY14E EPS slightly to $2.72 from $2.74 (consensus is $2.73). Management has stated for months that it would formally reassess its guidance after the Summer and we expect FY14 guidance to be increased by $0.05 to **$2.60-2.80**.

Lowering our FY14 expectations on lack of summer but still see a $0.05 guidance increase.

Management typically releases forward year guidance with fourth quarter results in February.

Figure 174: 3Q14 Earnings Walk

3Q13A Adj. EPS	0.76	*Notes*
PSE&G YoY	(0.00)	
Transmission Investments	0.04	*$171M rev increase eff Jan 1, 14 vs $174M last year so same 0.14 EPS*
O&M Growth	(0.01)	*Will be less than the pension reduction*
Pension	0.02	*Utility has about half the pension cost, which is declining by $125M*
D&A	(0.01)	*Ordinary uptick in depreciation*
Weather/Volume Impact	(0.03)	*3Q14 coolder than usual; ~20% decline in CDDs*
Other Costs, Taxes, etc.	(0.01)	
Power YoY	(0.05)	
Capacity Payments	(0.09)	*Lower in 2H14; decline from $242MW-Day to $166MW-Day*
Power Hedges, etc.	(0.02)	*Decline in Avg Hedge Price by $2/MWh in 2013 (on ~10 TWh)*
O&M Growth	(0.01)	*Will be less than pension reduction*
Bethlehem Outage	0.06	*Bethlehem CC down for major maintenance in 3Q13 - Exp & Lost volume*
Pension	0.02	*Power has about half the pension cost, which is declining by $125M*
D&A	(0.01)	*Ordinary uptick in depreciation*
Interest Expense	0.00	*Slight benefit from Power Refinancing*
Other Costs, Taxes, etc.	(0.01)	
Energy Holding YoY	0.01	*LIPA contract +0.03 in 2014 vs no contribution in 2013*
Corp.		
Corp/Other/Interest	0.01	Reversal of loss; potential uplift from asset sales
3Q14 Adj. EPS	0.72	
Street Consensus	*0.78*	
2014 Guidance Range	*2.55-2.75*	*"Upper-end of the range"*

Source: Company Filings, FactSet, UBS Estimates

Links to our relevant recent research are below:
[10/6/14 PPL Plus PEG: Weighing the Merits of a Bid]
[9/26/14 The Final Four on the Artificial Island]
[9/1/14 Bucking the Power Trend]
[6/2/14 Getting 'Stronger' from Power Constraints]

Weighing the Merits of a Bid

Management typically shies away from discussion of potential M&A but the media discussion earlier this month (TheStreet.com) will likely at least be commented on and come up in the Q&A. We prepared a pro-forma estimation of a potential acquisition of regulated-only PPA for a ~10% premium and projected that such a deal would be ~4% EPS accretive to PEG when utilizing 20% holding company leverage. **For more details refer to the related note**.

Utilizing more of PEG's balance sheet make sense, but PPL does not look like the most obvious target given limited accretion.

Artificial Island: PEG's project to lose – question is did LS Power propose enough?

As we discussed with the Dominion section above, the final proposals were submitted in late September for PJM's FERC Order 1000 Artificial Island project and the key question is whether this LS Power's lowest cost project offers enough reliability to overtake PSE&G and others. We caution against jumping to conclusions on any proposal, emphasizing the FERC 1000 process is not clear on the quality of the reliability solution (i.e. for how long does the solution 'fix' the identified constraint).

To cap or not to cap: competing on terms to win the bid

It is very difficult to handicap the odds but PSE&G is likely still in the lead after being selected as the winner previously. Previously PEG estimated the project would cost $280-320Mn but that included $80Mn for a Static Var Compensator which is not part of the new proposal. PEG has proposed a $221Mn cost cap and we still expect a decision in December on the latest proposals summarized below. For PEG, we estimate every $100Mn of spending is worth ~$0.01 EPS.

Solution quality is still quite unclear from proposals

Figure 175: "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

PEG joins PennEast project despite negative effect on basis

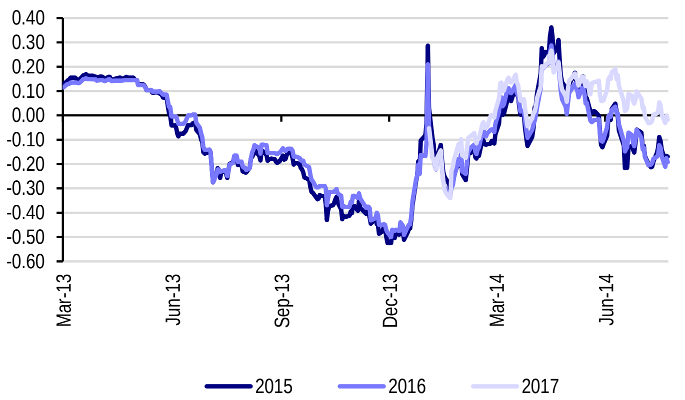
On Sept 18, PEG announced it would be joining the $1B PennEast pipeline project joint venture along with AGL Resources, NJR Pipeline Co, SJI, and UGI Energy Services. While PEG purchased a 12% stake as a partner and shipper, the other partners each have 22% stakes. The question remains to what extent the added resource will be available to PSEG to meet any FT needs of its system vs. underlying LDC growth. We continue to expect utilities – and especially electric utilities to take ownership in growth of pipeline efforts.

The PennEast Pipeline JV successfully completed its binding open season on Aug 29 and is now moving forward with public outreach and preliminary engineering

studies with a formal FERC application coming in the next few months and a decision expected in 2016. The project was announced in August to construct a 100-mile, 30-inch, 1 bcf/d pipeline from Luzerne County in the Marcellus down to Pennsylvania and NJ load at Transco's Trenton-Woodbury interconnection. PennEast is expected to cost $1B, with project management and operations handled by UGIES. After a 7-month construction phase, commercial operation could begin in November 2017 pending approvals from FERC, local, and state regulators.

The key question remains how this pipe could yet drive down TETCO M3 basis expectations further East; **we see the project as marginally negative for PSEG despite their support** – and its premium power and gas advantages over peers in PJM West. Notably, TETCO M3 basis is *higher* vs. Henry Hub in 2017, despite the added gas capacity from the Marcellus. While our previous analysis had suggested the pending expansion of the TETCO M3 pipe would be largely offset by growth in NJ-based gas generation, the latest expansion clearly will more than offset any limited regional growth (most new generation announced for 2017 appears biased in PA and OH, rather than NJ).

Figure 176: TETCO M3 Gas Basis vs. Henry Hub ($/MMBtu) – pipes should add downward pressure



Source: Platts and UBS estimates

PSEG Long Island Works With LIPA to Increase Potential While Lowering Risk With No Increase in Customer Bills

PSEG Long Island filed its $200Mn 2015-2018 'Utility 2.0' plan ($50Mn per year) in July and management commented that the Commission's feedback to the plan was that it was not ambitious enough indicating that there could be room for additional spending. As expected, PEG updated its proposal this month with $145Mn of further requests bringing the total to **$345Mn**. The key facilitation factor is that LIPA will be financing the spending with its own debt rather than PSE&G. Not only does this allow PEG to not have its capital at risk, the lower financing costs allows additional spending potential without increasing consumer rates. The spending will be based on performance contract so there is an opportunity for PEG to earn more than the ~$0.04/sh of EPS that $345Mn would imply from straight capex. As with Artificial Island's timing, we anticipate a NY Department of Public Service (DPS) decision this December.

We think the latest proposal would let PEG earn potentially earn more without having to put its own capital at risk.

Figure 177: Revised PSEG Long Island Utility 2.0 Long Range Plan

PSEG Long Island Utility 2.0 Long Range Plan V2 (October)		
Program	**Annual Demand Savings (MW)**	**Investment ($Mn)**
Direct Load Control Program	125	106
Residential Home Energy Manage.	20	16
Advanced Metering	20	25
Far Rockaway	27	81
Targeted Solar PV Expansion	30	15
Combined Heat & Power	5	6
Geothermal Heating & Cooling	5	10
Hospital Conversation	5	30
South Fork Infrastructure	13	55
Electric Vehicles Charging	N/A	1
Grand Total	**250**	**345**

Source: Company Filings

South Fork Improvements are $55Mn of the increased spending.

The base plan's initiatives are focused on reducing overall energy consumption and we reiterate that spending here will likely be immaterial at first (less than $0.01/sh earnings impact), but there is potential for an eight year-contract extension as well as for PSEG LI to provide more services for LIPA and increase the earnings contribution from the segment. The South Fork improvement grouping was originally listed as to be determined and relates to the east end of Long Island which is the area with the highest load growth; the subsequent update includes $55Mn of cost here with the supply portion still unknown. PSE&G estimated in 2012 that $294Mn of conventional infrastructure improvements would be needed for transmission reinforcements from 2017-2022 ($97Mn by 2017 and the balance by 2022). Rather than dedicating capital to traditional projects PSE&G LI has proposed a hybrid solution including distribution generation, storage, energy efficiency, and other renewable projects.

Figure 178: <u>Original</u> PSEG Long Island Utility 2.0 Long Range Plan

PSEG Long Island Utility 2.0 Long Range Plan V1 (July)		
Program	Annual Demand Savings (MW)	Investment ($Mn)
Utility 2.0 Investment		
Programmable Thermostats	100	60
Targeted Solar PV Expansion	30	45
Residential Energy Management	10	8
Incremental EE Expansion	10	30
Energy Conservation for Hospitals	5	30
EE Expansion for Rockaways	5	13
Combined Heat & Power	5	5
Geothermal Heating and Cooling	5	9
Total Utility 2.0 Investment	170	200
Capital Budget Investment		
South Fork Improvements	TBD	TBD
Advanced Metering	15	15
Total Capital Budget Investment	15	15
Grand Total	**185**	**215**

Source: Company Filings

Experiment on new rate constructs for recovery

PSE&G LI proposes either a 'performance driven investment' or 'savings driven investment' recovery model with the former resembling a more traditional rate case with a predetermined ROE and reasonableness band. The savings recovery model would be focused more on energy savings and the proposal states that consumer rates will not be impacted before 2016 when it anticipates the benefits of the EE, DR, etc. policies will be in effect. If LIPA opts to defer revenue increases for Utility 2.0 beyond the 2015 rate case the amounts would possibly be captured in the 2018 rate case (current three-year distribution rate freeze).

Complying with latest PJM capacity market reforms likely not as costly as some think

PEG Power's dual-fuel capabilities and nuclear backbone leaves the firm in an advantageous position and likely winner for the next PJM capacity auction.

Following the latest proposed PJM capacity reforms, PEG Power looks well positioned in PJM given its nuclear fleet and dual-fuel capabilities. Nearly half of PEG's installed capacity is gas fired although ~55% of the generation in 2013 was generated by the nuclear fleet. In the first quarter PEG's dual-fuel coal units (Hudson and Mercer) ran on gas as needed while the dual-fuel peakers utilized oil. The performance requirements for PJM's Capacity Performance may require some operators to pay for firm transportation capacity or retrofit their fleet but <u>PEG's combination of nuclear and dual-fuel should mitigate that risk of high compliance costs</u>. The Bethlehem Energy Center has firm gas transportation capacity and there is 1.3bcf/day of firm transportation for the Basic Gas Supply Service (BGSS) needs but that is only available for power generation after PSE&G gas customers are served.

We continue to view complete gas firm transportation (FT) as too expensive and largely unnecessary with partial FT and dual-fuel capabilities being a more realistic solution. While the rules and parameters of the upcoming PJM auction continue to evolve, we presented our initial detailed thoughts on the compliance alternatives

for Capacity Performance in our note last month '**Effectuating the Carbon Agenda**'.

Taking First Steps in 2014 to Make NJ Stronger

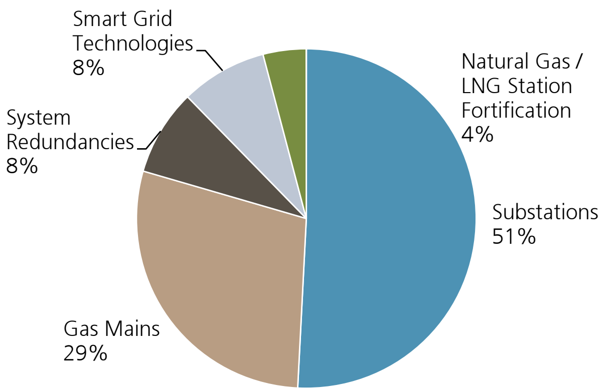
Now that PEG has formally incorporated the $1.2Bn into its capital spending plan, the question becomes – what's next in terms of storm hardening and the $2.7Bn of original unapproved spending originally contemplated. The next leg of gas spending could be proposed as early as the next two years but the bulk of the first $1Bn relates to substations where work is anticipated to take the full five years. As a reminder the first $1Bn of spending has an authorized ROE of 9.75% with recovery on an accelerated six-month timeframe. It is conceivable that management could spend $100Mn on gas cast iron main replacement in 2014 as the $400Mn of spending is set for a two year time frame. The company has started some work on elevating electric substations and the balance of activity in 2014 could be in the ~$50Mn range. The balance of the spending will be recognized in rate base when PSE&G files its distribution-only rate case at the end of 2017. This case will have three months of actuals and nine months of forward projections on the entire spending and not just for the Energy Strong portion.

On the infrastructure spending excluded from the settlement agreement: "Not as a no on the other stuff, but as a not yet" - PEG CEO Ralph Izzo 1Q14 Call

And Izzo said new gas capex could come in two/three years.

Possible that PSE&G could spend $150Mn on Energy Strong in 2014.

Figure 179: Energy Strong Settlement Agreement Spending (%)



Source: Company Filings

2014-2017: ~$1Bn of capex est. 2018: Remaining ~$200Mn est.

Efficiently Asking For More EE Funds in NJ

PSE&G filed with the NJ Board of Public Utilities (BPU) in August to continue its Energy Efficiency Economic (EEE Extension II) program with continued customer recovery at its existing ROE (10.3%) and capital structure. The program structure looks to be very similar to the previous proposal with a 1.5% participation fee being one of the few novel aspects.

(1) $30Mn for Multifamily Housing (45 project backlog)

(2) $40Mn for Hospitals/Healthcare facilities (26 project backlog)

(3) $25Mn for Government/Non-Profit (PSE&G is asking for permission to extend this to small business customers as well)

(4) $15Mn for Administrative, IT enhancement, and other

PSE&G's filing included "strong support" from the Natural Resources Defense Council (NRDC), Sierra Club, and other parties supported the initial filing so we do not anticipate material pushback with the request, perhaps only on the ~$15Mn of administrative costs. Even with the overhead costs, management estimates that the program will increase average electric and gas customer bills by less than 0.05%, respectively.

A procedural schedule has not yet been set but a decision is expected in 1H15 (filing includes an assumed effective date of March 1, 2015).

Docket: EO14080897

The Power Strategy: What to do with the business

Weighing new build in New England asks question of where to next?

New New England Capacity brings to light Power strategy for PSEG

We flag the company's recent indications it would seek to bid into the ISO-NE capacity auction to develop a new 450MW CCGT (at its existing Bridgeport site) brings about questions around the strategic priorities for the company—both with respect to its use of cash and its strategic direction. While likely a good value (assuming gas deliverability/dual fuel considerations are addressed), we broadly continue to look from management as to an indication of the future ownership of this business. Given its smaller footprint in this market – and favorable dynamics – we aren't necessarily surprised to see be the focus of its development; we suspect the bulk of incremental capacity in New England will be sourced in Connecticut.

With the economics of the plant at $600-700 Mn, this implies ~$1,400/kW for the economics of this brownfield site. We understand the plant would likely be developed with the 7-year fixed capacity entry

Christie Brings NJ BPU back to Full Strength

The NJ BPU will have a new President, Richard Mroz (R), following his appointment by Governor Christie and unanimous Senate confirmation. Mroz will replace Dianne Solomon who will remain on the BPU and serve through 2018. The Senate also approved Democrat Upendra Chivukula which brings the BPU back to a full five-member Commission with Fiordaliso (D) also having his term extended to 2019. We summarize the Commission below:

- *New* Richard Mroz (R): President appointed through March 2015
- *New* Upendra Chivukula (D): Appointed through March 2020
- *Previously President* Dianne Solomon (R): Extended through October 2018
- Joseph Fiordaliso (D): Extended through 2019 subject to confirmation
- Mary-Anna Holden (R): Serving through 2017

More clarity on PSEG's 'black box' but no timeline

PSEG Power's cost-based bidding errors in PJM continue to be a question mark.

It does not appear as if there have been any material developments on PSEG's cost-based bidding issue since 2Q earnings but we anticipate the issue appearing again on the call. The company believes it overstated the emission allowance on some of its fossil plants (and potentially other errors?) hence overstated costs and collected excess revenue. As management self-reported the errors to the relevant regulators (FERC, PJM, and the associated Independent Market Monitor) we would not anticipate substantial penalties/disgorgement but due to the amount of uncertainty the issue continues to attract Street attention. We remain somewhat concerned here as (1) the $25Mn is management's lowest estimate; and (2) the company is unable to determine a magnitude that is more likely than not. Management reiterated that it expects no ongoing impact on Power's earning profile.

Going forward, impact here (if any) might be classified as non-operating.

The emission component of bidding is de minimus compared to other costs but we remain somewhat concerned by the lack of disclosure as to how long the modelling error existed or even the amount of the liability booked. The first quarter charge was insignificant (~1% of expected 2014E) and will likely remain immaterial. We had assumed that the (previously undisclosed) charge in the first quarter flowed through retained earnings and was not excluded from operating earnings given the one-time nature of the historical event but management opted to include in 1Q14 ongoing results. This does not look like a clear-cut decision and we would not be surprised to see management opt to exclude any future potential charges when the issue is finally resolved.

Weak Summer Could Trim Results But Still At Top-End

Still at the top-end of the 2014 adjusted EPS guidance range.

Below we present our latest operating earnings estimates for 2014 and we remain near the midpoint for PSE&G and above the high end of Power. Given that management's original 2014 guidance did not include the 1Q14 weather uplift, we fully expect results to at least come in at the midpoint of guidance even with the lack of a summer uplift. As mentioned above, we look for a $0.05 increase in guidance to **$2.60-$2.80** which would leave management with latitude room for a full year beat with a few pennies above the midpoint on our latest numbers.

Figure 180: 2014 PEG Guidance vs. UBS Estimates

	2014 Operating Earnings	
	Guidance	UBS Est
PSE&G	$705-745	718
Power	$550-610	625
PSEG Enterpris	$35-40	38
Total	$1,290-1,395	1,381
EPS	$2.55-$2.75 - High-end	2.72
EPS - Consensus		2.73

Source: Company Filings, FactSet, and UBS Estimates

Valuation: Maintaining our $40 Price Target

Keeping our Neutral rating but see PEG as one of the bigger winners from the proposed PJM reforms given its nuclear/dual-fuel fleet.

Our valuation is based on SOTP analysis with a tweaked methodology at the Power business. We value PSEG Power at 9x EV/EBITDA and continue to normalize for capacity payments above $120/MW-day and give credit for the forecasted next three years of premium capacity payments. On the regulated business we have not changed our methodology and still ascribe a 0.5x turn premium P/E to '16E peer group for the heavy transmission focus (36% of PSE&G rate base at the end of 2013). While New Jersey is not the most constructive regulatory state and we remain cautious overall, we believe the premium valuation is appropriate for the abundance of opportunities available to the regulated utility as well as its strong rate base growth projected through the forecast horizon.

Latest Long Island 'Utility 2.0' allows for greater earnings and lower risk – facilitating an argument that our 6.0x multiple is too conservative.

We also apply a 6x multiple to the Enterprise/PSEG Long Island segment, which is primarily the LIPA services contract. We see this multiple as appropriate given the ten-year contract duration initially of its Services contract (a higher multiple could be warranted if the outlook for renewal of the contract beyond ten years is improved). The second round of Long Island proposals which include $345Mn of potential spending (financed by LIPA) could support a higher multiple as well. We are maintaining our Neutral rating but view PEG constructively given clarity on Energy Strong and the potential significant uplift from the proposed PJM reforms. Winning the Artificial Island contract could drive a positive EPS revision as well as incorporation of the latest LIPA 'Utility 2.0' opportunities.

Figure 181: Updated PEG EPS Estimates

	2012A	2013A	2014E	2015E	2016E	2017E
PSEG Power	1.27	1.40	1.23	1.02	0.87	0.78
PSE&G	1.04	1.21	1.41	1.57	1.74	1.90
PSEG Enterprise & Other	0.13	(0.03)	0.08	0.09	0.12	0.11
Total	***2.44***	***2.58***	***2.72***	***2.67***	***2.73***	***2.80***
Prior	2.44	2.58	2.74	2.68	2.69	2.76
Consensus			**2.73**	**2.70**	**2.77**	**2.85**
% Regulated	43%	47%	52%	59%	64%	68%
Regulated EPS CAGR ('13-16')					13%	
Guidance		**$2.40-$2.55**	**$2.55-$2.75 - High-end**			

Source: Company Filings, FactSet, and UBS Estimates

Figure 182: Updated PEG Utilities Sum-of-the-Parts Analysis – Maintain $40 Price Target

Sum of the Parts Analysis - Hedged Analysis - UBSe							
All figures in USD millions except per share	**2016E Adj. EBITDA**	**EV/EBITDA & P/E Multiple**			**Enterprise Value**		
		Low	Base	High	Low	Base	High
PSEG Power	1,153	8.0x	9.0x	10.0x	9,224	10,377	11,530
Capacity Price Normalization @ $120/MW-day	(156)	8.0x	9.0x	10.0x	(1,251)	(1,407)	(1,563)
PSEG Enterprise /PSEG LI (LIPA)	82	5.0x	6.0x	7.0x	409	491	573
Corp. & Other	-	4.0x	5.0x	6.0x	-	-	-
Total / Implied	*1,079*	*7.8x*	*8.8x*	*9.8x*	*8,383*	*9,461*	*10,540*
Subtract: Net Debt						(2,534)	
Add: Three years of PS Premium Capacity Pricing (NPV) over $120/MW-day						475	
NPV of Power and Non-Reg Equity					5,848	7,402	8,006
Number of Shares Outstanding (2016E)					508	508	508
Power & Holdings Equity Value per Share using Hedged EBITDA					$11.52	$14.58	$15.77
Maintenance Capex						($198)	
FCF (EBITA - Maintenance Capex)						$906	
Implied FCF Yield on Power Equity						*12.24%*	
	2016 Net Income/EPS	**P/E Multiple**					
PSE&G Net Income	883	13.8x	14.8x	15.8x	12,188	13,072	13,955
	Peer Multiple =		*14.3x*				
	Premium/Discount =		*0.5x*				
Number of Shares Outstanding (2016E)					508	508	508
PSE&G Equity Value Per Share	$1.74				$24.02	$25.76	$27.50
Total Equity Value per Share					$35.68	$40.34	$43.45

Source: Company filings, FactSet, and UBS estimates

SCANA Corp. (Neutral; $52 PT)

Slight 3Q miss $0.97 vs consensus $1.00; VC Summer concerns dominate

For the 3Q, we expect a slight miss at **$0.97** vs consensus $1.00, with somewhat cooler weather than normal this year (last year's EPS was weather normalized). We calculate that weather-normalized electric sales growth this year has been tracking at about $0.04/quarter this year (ahead of management's flat forecast): in 1H, electric revenues grew $0.21 and gas revenues grew $0.08, excluding $0.16 of 1Q weather benefits. Subtract $0.13 of BLRA increases from the electric increase and about $0.08 remains for 1Q an 2Q combined. The $67.2M BLRA increase in June should impact 3Q at about $0.08. At SCE&G, there's no impact from gas rate stabilization YTD, but we expect a $3M rate decrease on Nov 1, 2014 to adjust the gas ROE back to 10.25%. We assume -$0.02 from 3% higher O&M this year and another -$0.02 for D&A and -$0.02 for higher interest expense as well. Dilution from the 6.6M shares added in March 2014 hits another -$0.02.

Importantly, both owners SCE&G and Santee Cooper accept neither the preliminary revised schedule nor the extra cost impact from the delay, with both now subject to negotiation before SCE&G makes a special BLRA filing for recoupment, if any.

With TTM at $3.75 based on our 3Q estimate, we see SCG finishing the year at the top end of their $3.45-$3.65 guidance range. O**ur 2014 estimate** of $3.65 reflects our assumption that they would keep much of the weather benefit earned earlier this year. The company does not expect to initiate 2015 guidance until 4Q results in February 2015. Our 2015/2016/2017 estimates remain unchanged at $3.75/$3.95/4.20. Our PT of $52 based on 2016 average peer P/E.

Figure 183: 3Q14 Earnings Walk

3Q14 Earnings Walk	EPS
3Q13 EPS	**$0.94**
Sales Growth (co guid -0.2% decline in 2014)	$0.04
Base Load Review Act (BLRA)	$0.08
E&G Gas Rate Stabilization Case	$0.00
Weather in 3Q14 (weax norm in 2013)	($0.01)
O&M +3% in 2014	($0.02)
D&A	($0.02)
Interest & Other	($0.02)
Dilution (6.6M shares issued in March 2014)	($0.02)
3Q14 UBSe	**$0.97**
Consensus	*$1.00*
2014 Guidance	*$3.45-$3.65*

Source: UBS estimates, Company filings, FactSet

Nuclear cost increase probably higher than Staff expected; but not final

On Oct 2, the VC Summer nuclear construction consortium provided a preliminary cost estimate related to delays as it continues the process of re-baselining the Unit 2 and Unit 3 construction schedules. The estimate pertains only to the contract's non-fixed/non-firm portion (roughly 1/3 of the total), with the fixed portion (2/3rds of the total) borne by the consortium and thus unchanged as far as owners SCE&G and Santee Cooper are concerned. SCE&G's 55% portion of this preliminary estimate is approximately $660M for extra non-fixed costs borne by the consortium under the contract. This estimate does not include escalation from 2007 dollars, although we note that as of the August 2014 BLRA report, the project was still forecast to come in $706M under the 2009 budget due to improved escalation factors (i.e., inflation continues to be lower than originally expected). Importantly, both owners SCE&G and Santee Cooper accept neither the preliminary revised schedule nor the extra cost impact from the delay, with both now subject to negotiation before SCE&G makes a special BLRA filing for

Our impression from recent discussions with Staff is that the $660M preliminary (and pre-negotiated) figure is higher than they expected, especially compared to SCG's previous estimate of ~$200M of delay costs in June 2013. Our impression is that regulators could face some political headwinds if the figure is not negotiated downward.

recoupment, if any. At this time, the company has no estimate of when they will finish negotiations and be ready to make this filing.

Our impression from recent discussions with Staff is that the $660M preliminary (and pre-negotiated) figure is higher than they expected, especially compared to SCG's previous estimate of ~$200M of delay costs in June 2013 (before many of the problems with Lake Charles became major scheduling issues). With the Staff just beginning to study the reports and the company just beginning its negotiation phase, it's still too early to predict the outcome of recoupment. However, as things stand now, our impression is that while regulators remain generally supportive, these preliminary cost figures could result in some political headwinds if not reduced. On the other hand, a legitimate counterweight to such pressures would be the fact that the project is currently $706M under the 2009 budget as a result of reduced escalation. We also believe that Staff may have been surprised by the keeping of a 12-month separation between Units 2 and 3 in the preliminary revised schedule, especially considering that Unit 3 had been tracking ahead of schedule and that lessons learned from Unit 2 have tended to compress the completion dates between them even in past delays.

Owner costs could be significant, but mitigated by liquidated damages provision

SCG may be entitled to seek liquidated damages that could mitigate such costs.

Both owners also bear separate non-contract costs of their own (e.g., man-hours for their own employees on-site) that may be significant. However, with the Consortium indicating substantial completion of Unit 2 in late 2018 or 1H 2019 (Unit 3, 12 months later), this is about a year past the previous expectation of 4Q17-1Q18 and past the 18-month contingency period allowed by regulators that ends in Sept 2018. Since the delays would push the project out beyond the consortium's contracted March 2017 deadline, SCG may be entitled to seek liquidated damages that could mitigate such costs.

Project status - new delayed schedule is still pending

All 47 submodules for critical path module CA-01 (steam generator) are now in fabrication or on-site, with lifting and welding begun in the Module Assembly Building. Fabrication of CA-01 submodules at Lake Charles is being monitored closely by SCG. Fabrication of CA-03 (refueling water storage tank) submodules is occurring at SMCI facilities at Lakeland, Florida after having been moved there from Pegasus Steel earlier this year. Both modules and the second ring of the containment vessel are expected to be in place by the end of this year. CA-05 (chemical and volume control tunnel) is then installed next, with all 8 submodules now on-site.

For Unit 3 (12 months behind Unit 2), Oregon Iron Works and Toshiba/IHI have begun fabrication of CA-20 and CA-01 submodules. On May 21, Oregon Iron Works announced its acquisition by Vigor Industrial, although no key personnel are expected to change.

For further details on SCANA's nuclear developments please refer to our recent notes '**Rebasing Expectations**' and '**Nuclear Schedule Likely Out the Window**'.

Long-term growth projection unlikely to be revised until Feb 2015 earliest

Management continues to project 3% O&M growth and an effective income tax rate of 32% for 2014. The 3-5 year growth rate target remains 3%-6% and is supported by unemployment of only ~4.8% in SCE&G territory vs 6.1% nationally.

No secondary equity issued this year

Management now plans to postpone any secondary equity issuance into 2015.

The 2014-18E capital plan calls for a target of 52%-54% equity with issuances of $2.15B of debt and $825M of equity (~half from 401k/DRiP), including $600M of debt this year ($300M complete) and $200M of equity this year ($50M of DRiP complete). However, consistent with indications given during the 2Q call, management now plans to postpone any secondary equity issuance into 2015, given strong weather-driven cash flows YTD of approximately $20M after tax and a slight delay of ~$75M of nuclear capex out of 2014 (and ~$20M out of 2015) into future years.

ROE's remain healthy; no ratecases on the horizon

SCE&G electric earned ROE for the TTM in June was 10.00% (ex-VC Summer new nuclear construction), a slight decline from March levels of 10.20% vs an authorized 10.25%. Management's stated goal is to keep this within a range of 9.00%-10.25% and avoid any need for a general electric rate increase during the heaviest nuclear construction period, when BLRA increases are at their peak (2014-2016). The next expected BLRA rate increase of 2.82% is scheduled for November as recommended by Staff and according to plan. SCE&G Gas earned 10.94% for the TTM, an improvement from 10.69% in March vs 10.25% authorized. Gas rates in South Carolina are adjusted through the Rate Stabilization Act, with a small $3M decrease expected on Nov 1 to bring the ROE back down to 10.25%. PSNC earned 11.45%, also an improvement vs 11.31% in March, vs 10.60% authorized.

Valuation: No Change to $52 PT

We previously reduced our 2016-17 estimates by a nickel to reflect our tuning of assumptions for load growth, O&M and earnings growth. We continue to value SCE&G at a 10% discount to the average 2016 electric utility P/E and PSNC at a 5% discount to the gas LDC P/E. Unregulated SCANA Energy Georgia is valued at 5X 2015 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 side lines until better clarity on the early-stage execution risk for VC Summer Units 2 and 3. We believe timeline on getting sufficient clarity for investors to be comfortable is a 2015 at earliest, with SC PSC needing to bless any delay first. Moreover, with key years of capital spend in 2014 and 2015, we expect the delay to linger during this higher risk execution period.

Figure 184: UBS Estimates for SCG, 2013-2017E

EPS By Segment	2013A	2014E	2015E	2016E	2017E	2018E
Carolinas	$2.82	$3.10	$3.07	$3.37	$3.55	$3.66
PSNC (Gas Utility)	$0.37	$0.48	$0.46	$0.50	$0.52	$0.56
Parent/ GA Retail	$0.20	$0.07	$0.21	$0.05	$0.13	$0.13
Consolidated	**$3.39**	**$3.65**	**$3.75**	**$3.92**	**$4.20**	**$4.34**
Prior UBS Estimates	**$3.39**	**$3.65**	**$3.75**	**$3.92**	**$4.20**	**$4.34**
Growth Rate	*7.5%*	*7.7%*	*2.8%*	*4.5%*	*7.1%*	*3.5%*
Mgmt Guidance		**3.45-3.65**				
Long-Term Guidance (3-6% Range)						
High		3.60	3.82	4.05	4.29	4.55
Med	*3.40*	*3.55*	*3.71*	*3.88*	*4.05*	*4.24*
Low		3.50	3.68	3.82	3.98	4.14

Source: UBS estimates, Company filings, FactSet

Figure 185: SCG Sum of the Parts on 2016E

Scana
Sum of Parts

SCANA Corp Valuation Business Segment	Valuation Metric	2016	Low Case Valuation Multiple	Low Case ($s MM) Value	Peer Multiple	Base Case Prem/ Discount	Base Case Valuation Multiple	Base Case ($s MM) Value	High Case Valuation Multiple	High Case ($s MM) Value
Regulated Business										
SCE&G Franchised Electric	P/E	$3.37	12.6x	$6,498	14.5x	-10%	13.1x	$6,757	13.6x	$7,016
PSNC	P/E	$0.50	14.2x	1,094	15.5x	-5%	14.7x	1,133	15.2x	1,171
SCG Utilities Equity Value				**$7,592**				**$7,889**		**$8,187**
Georgia Retail (Net of Corporate)	EV / EBITDA	$25	4.0x	$101			5.0x	$126	6.0x	$151
Total				**$101**				**$126**		**$151**
SCG Equity Value				**$7,693**				**$8,015**		**$8,338**
Fully Diluted Outstanding Shares (2016)				154				154		154
SCG Equity Value per Share				**$50.04**				**$52.14**		**$54.24**

Source: UBS estimates, Company filings, FactSet

Sempra Energy (Buy; $116 PT)

We look for a relatively in-line quarter, with update for REX; upside from updates on both REX expansion and Cameron 4/5 expansion.

We project an in-line result tracking toward the middle of FY 2014 guidance.

We estimate that Sempra will report 3Q14 adjusted EPS of **$1.22**, in-line with early consensus of $1.26. SDG&E is weather decoupled but should experience growth over 2013 in-line with guidance. SoCal Gas benefits $5.8M pretax from the gas cost incentive mechanism. South American operations continue to see a weakening of currencies vs the US dollar, although a simultaneous weakening of the Mexican Peso should have a mitigating effect on liabilities. Renewables drops -$0.08 as a result of the 1x $24M gain last year from the sale of a 50% interest in Copper Mountain Solar 2 and Mesquite Solar 1 to the JV with Coned. Natural gas operations are expected to improve +$0.04 versus a negative 3Q13 as a result of fluctuations in the use and value of gas storage during the summer months. We expect parent to be flat yoy.

Figure 186: SRE 3Q14 Earnings Walk

SRE 2Q14 Earnings Walk	EPS
3Q13 Adj EPS	**$1.19**
SDG&E	$0.06
SoCal Gas	$0.02
Sempra International	
South America	$0.01
Mexico	$0.00
F/X Impact	($0.00)
US Power & Gas	
Renewables	($0.08)
Natural Gas	$0.04
Parent	($0.01)
Dilution	($0.01)
3Q14 Adj EPS	**$1.22**
Adjusted Consensus	**$1.26**
FY Guidance (Midpoint)	***$4.25-$4.55***

Source: Company Filings, FactSet and UBS Estimates

Upcoming catalysts

Sempra certainly has a lot going on – and with it – a lot of upcoming catalysts. We flag a few particularly relevant data points to keep scanning for:

- **Contracting datapoints for LNG exports:** This remains among the most important, with a formal study on ECA export facility sizing completed by year end. We believe pricing on deals, rather than if a deal can be done remains key – and a constructive datapoint vs. market today.
- **Sale of Mesquite CCGT:** Remains a clear priority by year end to divest the last of its true merchant power exposure. Pricing here will set expectations for others potentially seeking to exit this market
- **YieldCo vs. MLP decision:** Don't expect announcement, but certainly nuggets on latest thinking with 3Q call. Suspect action before 4Q results however.
- **Full REX pipeline details:** looking for finalization of the reversal contracts on the upsized east-to-west thoroughfare through Ohio. This is likely to become quite clear with 3Q.

Weighing the YieldCo vs. MLP Merits

We remain biased to think management opts for YieldCo

We emphasize the decision can be effectively boiled down to comparing the NpV benefits of enhanced General partnership stakes from a larger, more robust drop-down story when including the renewable sector – against the NPV of the tax benefits presented by an MLP structure. We emphasize under the MLP, Sempra can retain tax benefits generated by the renewables business at the parent for use later. We also suspect comfort with long-term viability of the YieldCo structure as a further moving piece, as well as size and credibility of a stand-alone MLP vehicle today given its modestly sized midstream business today.

MexiCo will drive YieldCo decision

We emphasize clarity around the size of SRE's midstream business could prove the crucial driver around whether management ultimately pursues an MLP or YieldCo of its renewable and midstream business. We emphasize should the US segments be awarded to Sempra, this could bias a decision towards an MLP (or at least make it a more ready option). Management generally sees the time line for each as comparable, with a structure seemingly in place by mid-2015.

Mexican projects: it's onto the project selection process

We look for updates in November around the initial two projects in Mexico, as well as datapoints in December around the initial two US-Mexican projects, which are anticipated to be bid through SRE's US Power & Gas segment.

REX: Open Season ends; look for developments later this month

With the non-binding open season for the 2.4 bcf/d expansion of REX having closed on June 27th, we look for **imminent** developments on next steps for an expansion of the East-to-West REX project (called "Clarington West") by the end of October, with a likely update contemplated with its 3Q call. Tallgrass Energy is currently in the process of collecting binding bids and controls the timing of the announcement, which by historical precedent could fall around 3-4 months after the June 27th close of the non-binding open season (this negotiation is a bit more complicated than the previous East-West piece, so maybe a little longer). We suspect the expansion of this size could yet garner substantial pricing, with our view that ~$0.50/MMBtu remains in the ballpark of reasonable (adding likely another dime of EPS, however capital spend on the upgrade remains unclear); the capex would appear incremental to management's plan.

How could SRE start a YieldCo? Couple solar + wind, with REX

We see the ~$60 Mn/yr (growing to near 100mn/yr through forecast period) in EBITDA from the renewable business, coupled with its 25% interest in the REX pipeline as sufficient to kickstart a YieldCo (we see the threshold as being a $50 Mn/yr run-rate), with clear line-of-site to continued drop-downs. Under current 1940 Act restrictions, management cannot start its contemplated MLP with a majority stake in the REX project given its passive investment stake in the project (just 25%; we estimate its going-forward EBITDA is ~$140 Mn/yr including the backhaul, albeit with the ongoing expansion). Rather, it would need to effectively pair a stake in the REX project with the renewable business initially.

Asset sales: Putting Mesquite on deck – still expecting by year end

Management recently formally put its remaining Mesquite power asset up on the block, reiterating its expectations for any contemplated sale would close by year end. SRE sold 625 MW of its 1,250 MW Mesquite Power, natural gas plant in Arizona, to Salt River Project for $371 million as of February 28th 2013 ($600/kW). (FERC approval docket: EC13-33) Management retains 625 MW in the project, with 270 MW contracted with the Southwest Public Power Resources Group under a 25 year contract beginning in 2015. The plant is in-service as of 2003, among the first new projects in the Southwest following the California Energy Crisis. Sempra natural gas purchases fuel to power its Mesquite Power plant.

Mgmt states interest is there – confident on timing by year end

Figure 187: Mesquite CCGT Economics – Looking to sell its last formal US Merchant Power Plant Soon

Economics:	2015E	2016E	2017E	2018E	2019E	2020E
Contracted (MW)	271	271	271	271	271	271
Merchant (MW)	354	354	354	354	354	354
Capacity Factor	65%	65%	65%	65%	65%	65%
Merchant Generation (MWH)	2,015,676	2,015,676	2,015,676	2,015,676	2,015,676	2,015,676
Contract Price ($/kW-yr)	$60	$60	$60	$60	$60	$60
Onpeak (Palo Verde), $/MWh	40.45	40.25	43.05	46.35	46.85	46.85
Revenues ($MM)	$98	$97	$103	$110	$111	$111
Gas Price SoCal	$4.38	$4.28	$4.32	$4.43	$4.43	$4.43
Fuel Cost per Mwh	$31.54	$30.79	$31.09	$31.86	$31.86	$31.86
O&M ($/kw-yr)	$15.45	$15.91	$16.39	$16.88	$17.39	$17.91
Non Fuel Vble costs per MWh	$0.79	$0.79	$0.79	$0.79	$0.79	$0.79
Fuel Cost	$36	$35	$35	$36	$36	$36
Spark Spread ($/MWh)	$9	$9	$12	$14	$15	$15
Gross Margin	$34.23	$35.33	$40.37	$45.46	$46.47	$46.47
O&M Cost	$10	$10	$10	$11	$11	$11
Other Cost	$2	$2	$2	$2	$2	$2
Total Costs	$47	$47	$47	$49	$49	$49
Gross Margin	**$51**	**$51**	**$56**	**$61**	**$62**	**$62**
Depriciation	$16	$16	$16	$16	$16	$16
EBIT	**$35**	**$35**	**$40**	**$46**	**$46**	**$46**
EBITDA	$51	$51	$56	$61	$62	$62
Interest	$14	$14	$14	$14	$14	$14
EBT	$21	$21	$26	$31	$32	$32
Tax	$7	$7	$9	$11	$11	$11
NI	**$14**	**$14**	**$17**	**$20**	**$21**	**$21**

Source: Company reports and UBS estimates

What are Key Considerations around Cameron 4&5?

Considering our view that shares have yet to fully reflect the LNG opportunity, we figured we would flag the following key factors as we look towards datapoints on this front to fuel shares higher into 2015.

Contracting opportunities remain key

Without a take-or-pay off-taker for the project, it is not happening. While we believe the project's brownfield economics give it a clear advantage over peer US projects, clarity on a contract through this year – and into 2015 remains key.

Brownfield status should yield a clear advantage.

What would the *ideal* case be? Existing off-takers expand their deal.

Ideally, management would like to see its JV Partners expand their current off-take to take down the further two trains, retaining the 50% ownership structure between the two entities. We believe realistically, we are likely to see other off-takers as necessary to enter the fray, with a focus on European, South American, and Asian markets.

Relying on existing off-takers is a likely assumption.

But Global LNG supply is increasing materially – limiting marketer interest

We flag our **European colleagues' latest report** on Global LNG markets, emphasizing a 40% increase in supply, limiting demand for further commitments from the likes of GDF Suez. As such, we see natural buyers are likely the incremental buyers of LNG; for further details on our views of LNG contracting, see our latest meeting notes from Cheniere Energy (NYSE: LNG) last week (**please click here to see our full note, Lone Star State Continues to Shine**).

What about the contract terms? We suspect terms could well be a bit lower than that of the original contracts signed by the initial batch of primarily marketing off-takers, seeing more competition regional (albeit less credible) terminals. The real primary competitor to Cameron remains LNG's ongoing efforts to expand both Sabine Pass (for trains 5&6) and Corpus Christie (seeking contracts for a third train). We continue to apply ~$3.30/MMBtu on the tolling arrangement for both the initial Cameron terminals – as well as the expansions.

Increased competition should weigh on contract prices.

Total costs could be comparable to initial trains, as labor hikes offset brownfield advantage: The actual cost of the facility will likely prove *lower* than trains 1-3 on a per unit basis, emphasizing the brownfield economics, but anticipate *higher* labor costs (which appear to be quite real; see our E&C colleague's **latest note on Gulf Coast inflation here**), which could offset much of these savings once under construction in 2017-2018 (the projected pinch point).

Labor escalation could offset brownfield economics to a degree…

All is not lost – perhaps a competitive advantage? Notably, we emphasize peer greenfield terminals are likely to be particularly disadvantaged by the continued inflationary trend. Management appears to be guiding the street to assume costs no higher than the last project ($9-10 Bn range, when fully loaded on the three trains), suggesting the two additional trains would cost ~$6 Bn. When applying comparable leverage of ~70%, we estimate Sempra's 50.2% ownership in the JV would approximate ~$900 Mn.

But same dynamics will also negatively impact greenfield development.

The Mexican LNG Export Opportunity: Defining ECA

While less defined than Cameron 4&5 in terms of opportunity, we look for an update from management following its ongoing market study around year-end. The key question remains whether management will opt to pursue one or two trains, depending on what it deems the market can bear. It appears Energía Costa Azul (ECA) is primarily focused on exporting volumes to FTA countries with the US, which would likely include Peru and Chile.

Premium location should drive results.

What are the merits of ECA? Closer to the Pacific Markets. ECA benefits from a ~$1/MMBtu advantaged shipping cost to West Coast/Asian locations vs. Eastern/Gulf Coast locations; this could yet prove the differing point to enable its development. We estimate delivery to Asia off this project is likely *less* than $2/MMBtu, with eastern terminals likely approaching $3/MMBtu.

The delivered cost of gas remains among the chief questions for the ECA project with SoCal Gas basis trading at a premium to other regions. We suspect continued growth in renewables – coupled with added East-to-West gas transmission

capacity (from Texas) enabled by Mexican exports could yet improve Southern California's basis. Moreover, with the risk of rising regional basis in the gulf coast from significant concentration of new gas demand, the region could yet eventually see a comparable gas acquisition cost. Please see our latest note on Texas for a further discussion of recent trends in regional gas basis. There appears a clear preference for projects capable of near-term delivery of volumes.

We look for an export study around ECA by year end

But who's the real contract target here? Question is to go FTA or not. The ECA project maintains a locational advantage to both Asian markets, as well as FTA markets in South America, which appear increasingly keen on importing US LNG – this includes Chile (the most likely candidate for electric-sector purposes), as well as Peru. The key question for the ECA project remains whether it will opt to pursue exports to FTA countries – or apply for a non-FTA export license from DOE. The delay in the project associated with applying for DOE approval could well set the project behind vs. competitors (there appears a clear preference for projects capable of near-term delivery of volumes, as evidenced by HECO's decision to opt for Fortis' Canadian option as part of its ongoing LNG import efforts).

Earnings estimates

We've tweaked our estimates up a few cents after updating the model post 2Q results and remain above Street consensus.

Figure 188: SRE EPS Estimates

Net Income	2014E	2015E	2016E	2017E	2018E	2019E	2020E
SoCalGas	$354	$385	$397	$417	$453	$497	$539
Guidance	*$325-$355*	*$360-$390*					
SDG&E	$510	$535	$554	$583	$613	$644	$673
Guidance	*$470-$510*	*$500-$540*					
South America	$186	$201	$213	$222	$235	$247	$261
Sempra Mexico	$174	$202	$227	$257	$286	$331	$387
Sempra International Total	$360	$403	$441	$478	$521	$578	$648
Guidance - Sempra International	*$355 -$380*	*$390 -$420*					
US Gas	$40	$46	$45	$45	$324	$420	$450
Renewables	$57	$50	$113	$272	$191	$132	$138
US Gas & Power Total	$97	$96	$158	$317	$516	$552	$588
Guidance - US Gas & Power	*$80-$100*	*$80-$100*					
Parent & Other	($200)	($199)	($240)	($378)	($384)	($371)	($368)
Guidance - Parent & Other	*($200)-($170)*	*($200)-($170)*					
Consolidated NI	$1,121	$1,221	$1,309	$1,418	$1,719	$1,900	$2,080
Guidance - Consolidated NI	*$1030 - $1180*	*$1130-$1280*					
UBSe EPS	$4.54	$4.82	$5.12	$5.44	$6.54	$7.16	$7.76
Prior UBSe	*$4.52*	*$4.81*	*$5.09*	*$5.41*	*$6.50*		
Guidance - EPS	*$4.25-$4.55*	*$4.60-$4.90*			*$6.00-$6.50*		
Consensus EPS	*$4.47*	*$4.87*	*$5.30*	*$5.72*			

Source: Company Filings, FactSet, and UBS Estimates

Valuation: Increasing Price Target to $116; Reiterate Buy

Below we present our updated summary Sempra sum-of-the-parts valuation (from $111 to $116) with the detailed valuation on the subsequent pages, updated for an expanded utility P/E multiple. We assume IENOVA's ability to capture ~15% of the total $120B incremental market opportunity from Mexican energy reform vs the 10% currently embedded in our colleague Lilyanna Yang's valuation. We feel this is justified given IENOVA's dominant position in Mexico with 25% of pipeline market share and 23% of gas compression station market share currently.

For renewables, we also apply the same multiples as we do for NextEra ahead of Sempra's announcement that it may be considering using the structure for its renewables (keeping the MLP accretion intact at Cameron as we believe

management would opt for Incentive Distribution Rights [IDRs] as NextEra and SunEdison did with their YieldCos).

Figure 189: Updated Summary Sempra Sum-of-the-Parts 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	$4.11
Gas LDCs	16x P/E	$0.72
Total Sempra Natural Gas		**$4.83**
Sempra US Power & Renewables		
Solar	14.5x EV/EBITDA	$0.67
Wind	8-15x EV/EBITDA	$2.00
Accelerated Depreciation Tax Shield and Other	NPV	$5.56
Total Sempra US Power & Renewables		**$8.22**
Cameron LNG Export Project		
Trains 1-3	NPV of 9x EV / EBITDA and MLP Accretion	$16.44
Accretion due to GP/LP Structure in MLP		$3.36
Trains 4-5		$2.07
Total Cameron LNG Export Project		**$21.86**
California Utilities		
SoCal Gas	17x P/E (1x premium)	$26.33
SDG&E	16x P/E (1x premium)	$34.60
Total California Utilities		**$60.93**
International		
SRE Mexico/IENova	Various	$30.08
Chile (Chilquita) - Unlisted	11x P/E	$4.33
Peru - Listed	Public Value	$5.26
Total International		**$39.67**
Less: Parent Debt	Book Value	($19.46)
Grand Total Sempra		**$116.05**

Source: UBs Estimates, Company filings

Renewables in a Yieldco structure add an incremental ~$1 GP value

Within our value above are higher EV/EBITDA multiples for the dropdown of renewable solar and wind projects into a YieldCo structure, which would add about $1.20 of value through the GP split. We flag that delaying the implementation of an MLP/YieldCo by a year into 2016 subtracts $0.40 of value at our 10.7% discount rate assumption (current assumption is 2015 start).

Figure 190: GP value of Yieldco with Renewable Dropdowns vs Without (By Year, beginning ~mid 2015)

GP Distribution ($M)	$ 1	$ 1	$ 5	$ 37	$ 100	$ 128	$ 130	$ 131
GP % of Total Distributions	2%	3%	7%	14%	20%	22%	22%	22%
Terminal Value								$ 2,382
Present Value of Distribution	$ 1	$ 1	$ 4	$ 24	$ 60	$ 70	$ 64	$ 58
Terminal PV	@ 8.1x terminal LP distribution							$ 1,054
GP Equity Value								$ 1,335
SRE Shares Outstanding								251
GP Equity Value Per SRE share								$ 5.31
							Previous value without renewable dropdowns	$ 4.12

Source: UBS Estimates, Company filings

Figure 191: Renewables Dropdown Schedule Assumption, 2015E-2020E

	2015E	2016E	2017E	2018E	2019E	2020
EBITDA	**$ 185**	**$ 221**	**$ 218**	**$ 215**	**$ 210**	**$ 206**
Net Income before GP interests	**$ 14**	**$ 22**	**$ 32**	**$ 79**	**$ 77**	**$ 76**
Equity earnings, net of distributions	$ -	$ -	$ -	$ -	$ -	$ -
Depreciation	$ 8	$ 50	$ 49	$ 48	$ 47	$ 46
Other	$ -	$ -	$ -	$ -	$ -	$ -
Provision for income taxes	$ 7	$ 12	$ 17	$ 43	$ 42	$ 41
Adjustment for maintenance capex	$ (2)	$ (3)	$ (4)	$ (10)	$ (9)	$ (9)
Total Distributable Cash Flow	$ 28	$ 81	$ 94	$ 160	$ 157	$ 153
% Dropdown	**20%**	**27%**	**40%**	**100%**	**100%**	**100%**

Source: UBS Estimates, Company filings

Figure 192: Renewables EBITDA Table

Renewables EBITDA table	2013	2014E	2015E	2016E	2017E	2018E	2019E	2020E
Renewables Total Adjusted EBITDA	**$27**	**$57**	**$61**	**$82**	**$181**	**$207**	**$204**	**$221**
Solar Projects:								
Copper Mountain I	14	14	14	14	13	13	13	13
Copper Mountain II -92 MW	15	14	14	14	14	14	14	13
Copper Mountain II -58 MW	0	0	1	7	7	7	7	7
ConEd JV Acquired Assets	0	0	1	34	34	33	33	32
Mesquite	0	11	11	11	11	11	11	10
Mesquite Expansion	27	26	26	26	26	25	25	25
Total	**55**	**66**	**68**	**106**	**105**	**103**	**102**	**101**
Wind Projects:								
Broken Bow 2	0	0	10	9	9	9	9	8
Auwahi Wind	2	1	1	1	1	1	1	1
Cedar Creek Wind II	15	14	14	13	13	13	12	11
Fowler Ridge Wind II	10	10	10	10	9	9	9	9
Flat Ridge Wind II	29	28	27	26	25	24	22	21
Mehoopany Wind	8	7	7	7	7	7	6	6
Total	**63**	**61**	**69**	**67**	**65**	**63**	**60**	**56**
PTCs	**41**	**41**	**48**	**48**	**48**	**48**	**49**	**49**

Source: UBS Estimates, Company filings

For further details on Sempra and our granular sum-of-the-parts, please consult our initiation report **'Adding Value at Every Turn'.**

Figure 193: SOP Valuation – Page 1 ($Mn unless otherwise indicated)

Sum of the Parts Analysis - UBSe	2015E Adj. EBITDA		EV/EBITDA & P/E Multiple			Enterprise Value		
Sempra Natural Gas								
Storage, Cameron (Import & Interstate) and REX								
			Low	Base EV/EBITDA	High	Low	Base	High
Storage	9		11x	12x	13x	$96	$104	$113
Exclude any contribution from Cameron LNG Import and Associated Pipeline Facility								
Cameron Interstate Pipeline (2018e)	26		9x	10x	11x	$233	$259	$285
Cameron Import [Off Existing Contracts]	25		6x	7x	8x	$150	$175	$200
REX Pipeline Valuation								
DCF Project Distributions w/o Backhaul Uplift in '15+ / No Value in '19+				*DCF @ 8%*			$392	
Add: Incremental Value of Backhaul (w/o volume expansion, net of cost)				*DCF @ 8%*			$109	
						Min @ BV	Total (From Above)	Plus '19+ Value
Equity Value (Primarily through Distributions to Parent)						$329	$501	$472
REX-Project Debt 2015 @ *25% Ownership - Excluded/Unconsolidated*						($765)	*($765)*	($765)
Gas LDCS								
				P/E				
Gas LDCS	11		15x	16x	17x	$171	$183	$194
Total Natural Gas Equity Value						$596	$1,223	$779
Total Natural Gas Equity Value per Share						$2.36	$4.83	$3.08
Sempra US Power & Renewables	2015			EV/EBITDA				
Renewables								
Solar (adjusted for SRE's Interest)	68		14x	14.5x	16x	$917	$985	$1,053
Wind (adjusted for SRE's Interest)	69		14x	14.5x	16x	$935	$1,004	$1,073
Wind PTC value	48		7x	8.0x	9x	$336	$384	$432
Total Value of Renewable Projects (ex- Accelerated Depreciation)						$2,188	$2,373	$2,558
Accelerated Depreciation Tax Shield NPV (2015+ Onwards) - NPV @ Parent of All Tax Benefits						$1,032	$1,032	$1,032
Solar-Project Debt 2015	(816)					($816)	($816)	($816)
Wind-Project Debt 2015 (unconsolidated OBS)	(882)					($882)	($882)	($882)
Total						($666)	($666)	($666)
Total Value of Renewable Projects - Equity						$1,522	$1,707	$1,892
Additional projects								
	MWs		$/kW					
Renewable Pipeline (Rosamond, Mesquite Expansion, ESJ Part II)	875		$100			$88	$88	$88
Mesquite CCGT (625 MW Remainder)								
	Sale Price in 2012:	*Haircut:*	*Book Value on B/S ($ Mn):*			$287	$287	$287
	$371	-23%		$287				
		Implied $/kW		$459				
US Power & Gas Portfolio Equity Value						$2,492	$3,304	$3,046
US Power & Gas Portfolio Equity Value per Share						$9.85	$13.06	$12.03
Cameron LNG Export Project								
Baseline Project Value				2020 EV/EBITDA				
2020 EBITDA	$874		8x	9x	10x	$6,989	$7,863	$8,736
Approximate Debt assuming 67.5% debt (per guidance)	($2,203)					($2,203)	($2,203)	($2,203)
Equity Value						$4,786	$5,660	$6,534
Implied per Share						*$18.91*	*$22.36*	*$25.82*
Accretion due to GP/LP Structure in MLP	Splits	1Q2018E				$1,157	$1,157	$1,157
Implied per Share	*(Net of Dilution from Midstream Acquisition)*					*$4.57*	*$4.57*	*$4.57*
Total 2020 Value Discounted @ 8% Back to 2016 (4-Years)	8%					$4,368	$5,011	$5,653
Opportunity on Train 4/5 (Assuming Build in 2021), per share							$523	
Cameron LNG Export and Potential MLP Equity Value						$4,891	$5,534	$6,176
Cameron LNG Export and Potential MLP Equity Value per Share						$19.33	$21.86	$24.40

Source: Company Filings, FactSet, and UBS Estimates

Figure 194: SOP Valuation – Page 2 ($Mn unless otherwise indicated)

California Utilities									
	2016 Net Income			P/E Multiple					
		Low	Group	Premium	Base	High	Low	Base	High
SoCal Gas									
SoCal Gas	$397	15.8x	15.8x	1.0x	16.8x	17.8x	$6,268	$6,664	$7,061
Implied per Share	*$1.57*						*$24.76*	*$26.33*	*$27.90*
SDG&E									
SDG&E	$554	14.8x	14.8x	1.0x	15.8x	16.8x	$8,202	$8,756	$9,310
Implied per Share	*$2.19*						*$32.41*	*$34.60*	*$36.79*
Total California Utility Value							$14,470	$15,420	$16,371
Total California Utility Value per Share							$57.17	$60.93	$64.69
International Segment									
Mexico (IENova)									
	2015 Adjusted EBITDA			**EV/EBITDA Multiple**				**Enterprise Value**	
SRE Mexico - Mexi-Cali CCGT	$31		11.0x	12.0x	13.0x		$343	$374	$405
SRE Mexico - Costa Azul LNG Import	$175		11.0x	12.0x	13.0x		$1,566	$2,100	$2,275
SRE Mexico - Midstream (non-PEMEX JV)	$142		11.0x	12.0x	13.0x		$1,566	$1,709	$1,851
PEMEX JV for Pipeline	$117		13.0x	14.0x	15.0x		$1,516	$1,633	$1,750
Baseline Midstream Business EV	$465		*10.7x*	*12.5x*	*13.5x*		$4,992	$5,816	$6,281
Net Debt (IENOVA)							($984)	($984)	($984)
PEMEX JV									
Net Debt (PEMEX JV)							($175)	($175)	($175)
Baseline Midstream Business Equity Value							$3,833	$4,657	$5,122
Implied value per Share of IENOVA (in Peso)							44.39	53.93	59.31
Official UBS IENOVA Price Target (pesos)							*$65.00*	*$83.00*	*$95.00*
UBS Assumption ($M US):				*Official $83 PT*	*Incremental*				
Total Mexican growth opportunity assumption (Midstream Pipeline, Gathering, Renewables, LNG Export, etc.)				$120,000	$120,000				
Capture Rate				10%	15%		*We assume 5% additional market share*		
Total Build for IENOVA				$12,000	$18,000		*than our Colleague Lilyanna Yang*		
Implied Annual EBITDA @ 15% ROE, 55% equity, 30 yr life				$1,720	$2,580				
Incremental EBITDA assumption					$860		$860	$860	$860
EV/EBITDA multiple							11x	12x	13x
Incremental EV							$9,460	$10,320	$11,180
Debt assumption					45%		$8,100	$8,100	$8,100
Incremental equity assumption							$1,360	$2,220	$3,080
Incremental equity assumption $US/sh							$5.37	$8.77	$12.17
Incremental equity assumption pesos/sh							$15.75	$25.71	$35.67
IENOVA valuation assumption for SRE $ Pesos							$80.75	$108.71	$130.67
Implued upside on current shares								*31%*	
Sempra Ownership (%)							81%	81%	81%
SRE-Owned Equity Value (UBSe + Growth Opportunity Upside at 50% weight) $US							$5,655	$7,613	$9,151
SRE Mexico- Total Equity Value per Share $US							$22.34	$30.08	$36.16
Market Value of Internationally Listed Subsidiaries									
			Mexico (IENova)		Peru (Luz Del Sur)				
Share Price			83.27		9.95				
Shares Outstanding (Total)			1,154		487				
Local Market Cap			96,094		4,845				
F/X Rate (MEX/USD and SOL/USD, respectively)			0.07		0.34			5,813	
IENova Market Cap (Mexico), USD			$7,191		$1,667				
Sempra Ownership (%)			81%		80%				
Sempra's Stake in Subsidiary			$5,831.74		$1,330.60				
Subsidiary Value per Share			$23.04		$5.26				
	2015 Net Income			P/E Multiple					
Chile (Chilquita)- Unlisted	$100		10.0x	11.0x	12.0x		$996	$1,095	$1,195
Implied per Share	*$0.39*			*Applying Peer Group Multiple*			*$3.93*	*$4.33*	*$4.72*
Total International Segment Value (Using UBSe for Chile/Mexico & Market Value for Peru)							$31.54	$39.67	$46.14
All Segments Value per Share							$117.88	$135.52	$147.26
Netting out the Parent Debt							($4,926)	($4,926)	($4,926)
Implied per Share							*($19.46)*	*($19.46)*	*($19.46)*
Shares Outstanding (2015E)							253	253	253
Total Equity Value per Share							$98.42	$116.05	$127.80

Source: Company Filings, FactSet, and UBS Estimates

Southern Company (Sell; $38 PT)

Expect an in-line quarter slightly above guidance; more focus on Kemper, Vogtle

We expect SO to report **$1.08** vs $1.07 consensus and guidance of $1.06. A return to normal weather vs a very mild 3Q13 helps +$0.10, but this is slightly offset by -$0.02 from a slightly milder than normal 3Q14. Rate relief and lower interest expense helps +$0.07, but this is offset by -$0.10 of higher O&M, an incremental penny of D&A, and -$0.03 of share dilution. Southern power is expected to be flattish overall for 2014 vs last year, but the expiration of the Dahlberg plant contract this quarter has a penny or two negative impact.

Heading toward the top end of the guidance range $2.72-$2.80.

Figure 195: 3Q14 Earnings Walk

3Q13 Earnings Walk		EPS
3Q13A Adjusted EPS		**$1.08**
Return to normal weather from 3Q13		$0.10
Weather in 3Q14, slightly mild - close to normal		($0.02)
Industrial Sales growth +3% YoY in 1Q		$0.01
Rate Relief		
GA- Base Rate Increase Jan 1 2014	36.8	$0.03
GA- Nuclear Cost Recovery	14.8	$0.01
MS Power - PEP	4.8	$0.00
MS Power- AFUDC on Kemper	7.8	$0.01
Gulf Power	10.5	$0.01
Southern Power		($0.02)
Lower Interest Expense		$0.01
O&M		($0.10)
D&A		($0.01)
Share Dilution		($0.03)
3Q14e Adjusted EPS		**$1.08**
3Q14 Guidance		*$1.06*
Consensus		*$1.07*
2014 Guidance		*$2.72-$2.80*

Source: UBS estimates, Company filings, FactSet

With TTM tracking in at $2.90 based on our 3Q14 estimate, we see 2014 earnings heading toward the top end of the guidance range $2.72-$2.80. The company is not expected to initiate 2015 guidance until the 4Q call in February, although we do expect updates on Kemper and Vogtle on the 3Q call and at EEI.

More delays and cost over-runs at Kemper

In an Oct 2nd 8K, Mississippi Power Co. announced that it expects the Kemper IGCC to be in service sometime later in 2015 than the previously forecast 2Q15 date. The company also announced related additional costs of around $88mn ($29M reported in their July PSC Report, and a further $59M reported in the August PSC Report) attributed to construction, start-up and operational readiness activities, including additional related contingency, as well as additional property taxes and insurance. A more specific revised in-service date and updates to the cost estimate will be reported in its ***September*** *Kemper IGCC Project Monthly Status Report* which will be filed by the end of October.

In service sometime later in 2015 than the previously forecast 2Q15 date. More details coming by the end of October.

We continue to be concerned about the potential for further write-downs due to delays in major milestones, flagging associated funding costs at ~$25 Mn/month (additional costs over the ~$2.9bn cap are not recoverable). With Kemper's startup now expected to be later in 2015 and Vogtle's capex spending peaking in

2015/16, we believe the risk profile for SO shares will begin to abate more meaningfully in ~2016 once these rivers have been crossed. The table below highlights how major milestones have been extended at Kemper over last few months.

Figure 2: Comparison of monthly Kemper IGCC status reports

Kemper IGCC Monthly Status Report	August 2014 Report	June 2014 Report	May 2014 Report	April 2014 Report	March 2014 Report
LDF Dome Completion	N/A	N/A	N/A	N/A	March-14
Turnover First Coal Silo	N/A	N/A	N/A	April-14	April-14
Pneumatic Pressure Test of Gasifier A	May-14	May-14	May-14	May-14	May-14
Start Radial Stacker Reclaimer Erection	May-14	May-14	May-14	May-14	May-14
Turnover Gasifier Feedwater Steam Trains A&B	July-14	July-14	June-14	May-14	April-14
Pneumatic Pressure Test of Gasifier B	June-14	June-14	June-14	May-14	May-14
Turnover First Cyclonic Baghouse	July-14	July-14	July-14	May-14	April-14
Turnover First Gasifier Lignite Dryer	July-14	July-14	July-14	N/A	N/A
Turnover First Pressurized Transport (Gasifier)	August-14	July-14	July-14	N/A	N/A
Back Flow of Steam System from HRSG	October-14	August-14	August-14	June-14	June-14
Piping "Pipe Tight" Installation Completion	August-14	August-14	August-14	August-14	June-14
First Fire Gasifier A	October-14	Sep/Oct-14	August-14	August-14	June-14
First Fire Gasifier B	Nov-14	Oct-14	N/A	N/A	N/A
Commission Ammonia Purification Package	Dec-14	Oct-14	N/A	N/A	N/A

Source: Company Filings

Vogtle VCM 10 passes vote 5-0; remains on-schedule

The 10th Vogtle Construction Monitoring report (VCM) was approved on Aug 19th in a 5-0 vote, with VCM 11 recently filed at the end of August. Hearings for VCM 11 will be held in 4Q with a vote in Feb 2015.

The next critical steps for Unit 3 remain the completion of the CA-01 module, expected later this year. Management has downplayed any minor delays that they may have encountered based upon the weather. Furthermore, the company could utilize double shifting and other mechanisms to ensure that the timeline is met (the VCM maintained the expected in-service for Units 3&4 in 4Q17 and 4Q18, respectively). A distinction was made between SO's contract with the CBI/Westinghouse consortium and SCG's contract for its identical VC Summer project, with management believing that SO's fixed-price/fixed schedule contract effectively incentivizes the consortium to remain on schedule whereas SCG is currently awaiting an amended schedule in 3Q. Nevertheless, VCM 11 states that "schedule pressures continue to challenge the project". Total construction and capital cost have remained at $4.8B through VCM 9-10-11, with 4% of the total 6%-8% total maximum rate impact to customers already in rates.

Southern Power considering another 125 MW solar, perhaps in 4Q

Management has been proactive in dealing with DG legislation before solar penetration gains scale in its footprint.

The recent acquisition of the 50-MW Macho Springs solar facility from First Solar brings SO's total solar portfolio capacity to 291 MW. While this project is still relatively small, recent FERC filings indicate that the company is considering another 125 MW as soon as 4Q14. We continue to expect Southern Power to acquire additional new solar projects with long-term contracts.

Georgia Power RFP should yield results toward the end of October

Final awards in late October

We expect an announcement for Georgia Power's central-station solar RFP winning bids by the end of this month, perhaps in time for the earnings call. We see contracted renewables in the Southeast as the sweet spot for Southern Power in coming years as the company could execute on ~400MW of the 425MW piece

of its utility-scale solar RFP (70MW scoped separately for a total of 495MW). We estimate this as an incremental ~$1.0-1.2 Bn investment opportunity for Southern Power, likely utilizing conventional renewable project finance structures (70/30 debt/equity). SO’s latest CapEx budget explicitly breaks out $1.4 Bn of "placeholder" growth projects from 2014-2016. (RFP Docket No. 36325, IRP Docket No. 36498). Following the acquisition of Macho Springs (~$200 Mn), we estimate the bulk of the remaining capital would be spoken for, however, management has been quick to add that this would not limit it from pursuing additional projects should it find such opportunities (we are a bit more skeptical given heightened competition for a smaller set of available utility-scale projects of late).

Increased industrial sales could indicate better economic outlook in Southeast

In 2Q, industrial sales grew 3% YoY, on par with our estimates, although the margins on industrial sales are low, so the effect on EPS was fairly nominal (+$0.03). Having said that, continued industrial sales growth (2Q marks the 13th consecutive month of year-over-year industrial sales growth) is constructive of an improving economic outlook in the region. Mgmt. was positive on the overall health of the local economy, citing strong exports from Alabama and Georgia (+4.1%) and recovering housing market. In addition, mgmt. indicated that 90% of the company’s major customers expected equal or better sales for the second half of the year. SO'S performance is heavily tied to economic activity, and should the momentum keep going, it could help SO mitigate the effect of other negatives in the rest of the year. Taking into account the

New nuclear possibilities; "just looking" for now

While management has indicated an interest in exploring the possibility of new nuclear development, after Vogtle, we emphasize that these considerations are very early stage at this time, without much in the way of concrete steps. Nevertheless, we believe that should the company target a mid-2020's in-service date, early planning steps would have to be initiated soon. While site(s) of potential further plants have not been identified formally (of the ~8 possible locations), we would suspect Georgia Power would remain the host for additional units given its size among the SO family. With construction work likely a late-decade or early 2020 datapoint, spend remains outside of the current view, but could well mesh to drive continued earnings growth in the long-term, a key concern for many shareholders. To the extent the company is successful in laying the ground work in this direction in coming years, this could speak to the aggressiveness of the company's corresponding dividend policy through the decade (which is slated to see a pick up through the slower earnings growth projected in the back half of the current decade); management's formal target has been to maintain its current $0.07/sh annual growth despite a slower EPS trajectory.

Is this part of a trend in the industry? Quite possibly to replace retiring nukes.

The broader question arising from SO's datapoint is to what extent the country intends to replace nuclear units that will see their 60-year licenses being expiring en masse in the late part of the 2020's. We see this issue as becoming a much more prevalent issue in coming ~3-4 years, as the subject gains greater clarity with regulated utilities (although discussion of 80-year licenses remains a rumbled concept in the nuclear world, albeit with additional retrofits needed).

Valuation: $38 PT and Maintaining Sell

The outcome of our sum-of-the-parts below is a 1.5x or a 9% discount to the average group P/E. SO currently trades at a slight premium to the average utility peer P/E multiple on 2016E.

The key question remains whether SO deserves a discounted P/E versus peers given its slowing capex profile and recent execution issues with both Kemper and Vogtle, despite its constructive regulatory regime? Historically, Southern has traded at a meaningful premium over its regulated utility peers; however, that advantage has evaporated.

Our valuation below ascribes an explicit discount of -2.0x and -3.0x to its Georgia Power and Mississippi Power businesses to account for the execution risk for both companies. For Georgia, we note a similar discount currently being applied to SCG in South Carolina with similar nuclear risk. We apply a higher discount to Kemper given the extended timeline and potential for additional slippage, write-downs, and equity raises.

We also shifted towards applying a -2.0x discounted multiple on SO Power on a P/E basis to reflect the greater risk profile of this business versus its rate regulated businesses (see section below for more details)

As for Alabama Power and Gulf Power, we apply an average multiple with no premium to account for the slower investment and load growth profile of these states despite the favorable regulatory environments and overall earned ROE.

Figure 196: UBS estimates for SO 2014E-2018E

SO EPS Estimates	2014E	2015E	2016E	2017E	2018E
Alabama Power	$0.83	$0.82	$0.79	$0.83	$0.87
Georgia Power	$1.47	$1.45	$1.54	$1.59	$1.62
Gulf Power	$0.17	$0.17	$0.17	$0.18	$0.19
Mississippi Power	$0.26	$0.25	$0.26	$0.27	$0.32
Southern Power	$0.20	$0.21	$0.22	$0.23	$0.24
Other	($0.12) -	($0.04) -	($0.02) -	($0.01) -	($0.01)
SO, UBS Estimates	**$2.80**	**$2.86**	**$2.95**	**$3.09**	**$3.22**
Guidance Range	2.72-2.80	2.80-2.91	2.89-3.03		
Prior UBSe	*$2.80*	*$2.86*	*$2.95*	*$3.09*	
Street Consensus	*$2.79*	*$2.87*	*$2.97*	*$3.07*	

Source: UBS estimates, Company filings, FactSet

Figure 197: Sum of the Parts Valuation, UBSe 2015: No More Premiums, and Discounts for GA and MS

			Low Case		Base Case			High Case	
Business Segment	Valuation Metric	2015	Valuation Multiple	Per Sh. Value	Prem/ Discount	Valuation Multiple	Per Sh. Value	Valuation Multiple	Per Sh. Value
Regulated Business									
Alabama Power	P/E	$0.82	14.10x	$11.60	0.00x	14.50x	$12.42	16.10x	$13.24
Georgia Power	P/E	$1.45	11.50x	$16.64	-2.00x	12.50x	$18.09	13.50x	$19.54
Gulf Power	P/E	$0.17	13.50x	$2.25	0.00x	14.50x	$2.42	15.50x	$2.59
Mississippi Power	P/E	$0.25	10.50x	$2.61	-3.00x	11.50x	$2.86	12.50x	$3.11
Southern Power (Contracted Merchant)	P/E	$0.21	11.50x	$2.47	-2.00x	12.50x	$2.68	13.50x	$2.90
Other	P/E	($0.04)	13.50x	($0.55)	0.00x	14.50x	($0.59)	15.50x	($0.63)
Southern Company Total/Implied		**$2.86**	***12.25x***	**$35.03**		***13.25x***	**$37.89**	***14.25x***	**$40.75**
Shares Outstanding					900	*Overall discount*			
Regulated Peer Group Multiple					14.5x	**-9%**			

Source: UBS estimates, Company filings, FactSet

TECO Energy Inc. (Neutral; $17 PT)

3Q weighted down by NMGC acquisition although expect to see slightly higher forward EPS estimates as Street integrates deal accretion of ~$0.02

Positive quarter, albeit in-line, as growth is forecasted to overcome initial NMGC dilution.

TECO Energy is estimated to report 3Q14 adjusted EPS of **$0.33**, in-line with consensus ($0.33) as the company continues its string of solid YoY growth, although it is offset by the negative drag from the recently closed New Mexico Gas Company (NMGC) deal. Management closed the acquisition of NMGC on September 3rd but unlike People's Gas which has more residential customers than NMGC, the earnings are shaped primarily in the first (~60%) and fourth (~40%) quarters. At the beginning of the quarter, (July 1-8) management issued 15.5Mn shares for net proceeds of $271Mn and 1.2Mn (approximately half of the allowable) for $21Mn as part of the NMGC financing. Equity dilution drags EPS by $0.02-0.03 and the slightly negative without any corresponding NMGC earnings offset. Offsetting the negative items include the continued YoY effect of the Tampa Electric rate increase as well as organic ratebase growth, reduce slightly by O&M increases. TECO Coal could face some issues during the quarter from rail issues although the company is on track to meet volume guidance for the year. The weather data does not appear to show any material deviations from the comparable period which was also close to normal.

We do not anticipate a change to FY14 guidance and see FY15 guidance at $1.05-$1.15 (expected with 4Q14 results).

Management reaffirmed its utility and consolidated guidance in September after the NMGC deal close. Following management's decision to reduce the size of the equity offering (and the underwriter's decision to exercise only half the green shoe) we now view the NMGC deal as closer to break-even in 2014. TECO's TTM EPS is $1.05 including 3Q14 estimates, at the top-end of the $0.95-$1.05 guidance range. We estimate that a weaker 4Q14 will keep FY14 guidance within the range due to dilution. Historically management announces guidance for the upcoming year with 4Q results in February and our initial 2015 adjusted estimate of $1.11 we believe guidance will be **$1.05-$1.15**.

Figure 198: 3Q14 Earnings Walk

3Q14 Earnings Walk	EPS	*Additional Commentary*
3Q13A Adjusted EPS	**$0.30**	
Utility		
Return to Normal Weather vs 3Q13	$0.00	*~Normal weather in 3Q13*
Impact of Weather in 3Q14	$0.01	*Slight increase in Florida/Tampa CDD YoY*
Tampa Electric Rate Increase	$0.03	*~$50Mn rate increase effective 11/1/13*
Ratebase Growth at Electric/Gas	$0.02	*$300M-$350M capex minus $100M depreciation*
Higher D&A	$0.00	*Small +$1.5M offset from change in software life*
Higher O&M	($0.01)	*Growing slightly but offset by $2M of storm reserve reduction*
Lower Interest Expense	$0.01	*Short Term Debt Balances*
TECO Coal	$0.00	*Expect ~breakeven for 2014 vs -$1.4M in 3Q13*
New Mexico Gas Co. (NMGC)	($0.01)	*Deal closed Sept. 3; no real EPS contribution in 3Q14*
Dilution	($0.02)	*16.7Mn shares issued around July 8th*
3Q14E Adjusted EPS	**$0.33**	
Consensus	$0.33	
2014 Guidance	*$0.95-$1.05*	

Source: Company Filings, FactSet, UBS Estimates

Links to our relevant recent research are below:

8/1/14 Synergy Step-Up

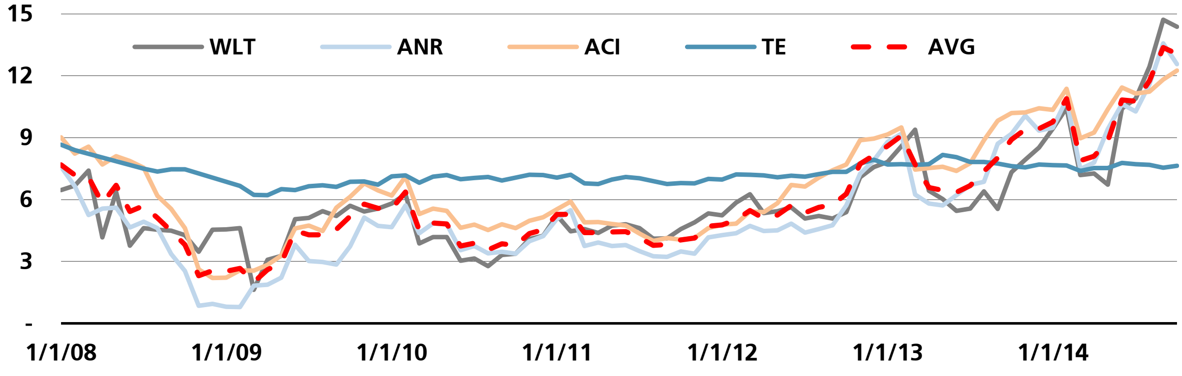
4/30/14 Pushing for a Finish in New Mexico

A potential TECO Coal deal continues to drag-on

The business was essentially break-even in 1H14 with the aid of depletion taxation and we view a similar outcome in the back-half of the year. Only 450,000 tons of Coal's expected volume for 2H14 is unhedged and we previously reduced our expected loss for the segment in FY14 slightly, bringing our estimate back toward breakeven. The company has likely suffered along with the coal industry in the face of transportation issues that have been a popular topic recently. TECO Coal is serviced by Norfolk Southern (Clintwood Elkhorn facilities) and CSXT Railroad (Burke Branch and Davidson Branch facilities). Management has confirmed numerous times that they have been in discussion with several buyers, but there have not been any commitments yet.

Mgmt continues to discuss a sale with potential buyers but there has been an high level of due diligence given the uncertainty in the coal market.

Figure 199: Recent Coal EV / EBITDA – Multiples setting multi-year highs lately



Source: FactSet

We are maintaining our valuation of Coal at ~$185Mn ($43Mn EBITDA at 4.5x EV / EBITDA reflecting benefits from loss on sale).

Our ~$185Mn after-tax expectation of proceeds on a Coal deal is unchanged but could be lower depending on management's urgency to sell.

After closing the $950Mn NMGC deal in September, TECO is financing the $190Mn 'shortfall' of the $950Mn transaction with a combination of cash and TECO Energy short-term debt. Management has stated that there is no real urgency in selling the Coal business as they can manage this financing 'gap' with TECO Energy credit facilities and the upcoming refinancing opportunity at the Parent. As of 6/30/14 the $200Mn TECO Finance revolver was unutilized and has an interest rate around 0.6%. $191.2Mn of TECO Finance debt matures next year and this could provide an opportunity to secure longer-term financing for NMGC. Alternatively, management could opt to secure financing in April/May with the TECO Finance (parent) maturity.

Figure 200: NMGC Estimated Financing

NMGC Estimated Financing ($Mn)	
Assumption of Debt	200
Private Placement of Debt at NMGI/NMGC	270
Equity Issuance	292
Cash/TECO Energy ST Debt	188
Total	**950**

Source: Company Filings and UBS Estimates

Integrating New Mexico into Our Estimates, Accretively

With the deal closed we now include the contribution from NMGC in our formal EPS estimates below which is a contributing factor to the slight accretion in 2015+.

Figure 201: Updated TECO Adjusted EPS Guidance

TECO EPS Estimates	2012A	2013A	2014E	2015E	2016E	2017E
Tampa Electric & People's Gas	1.05	1.05	1.13	1.20	1.22	1.39
TECO Coal	0.23	0.07	(0.02)	0.00	(0.00)	(0.02)
Parent	(0.15)	(0.18)	(0.10)	(0.09)	(0.03)	(0.00)
Total UBSe	**1.14**	**0.95**	**1.02**	**1.11**	**1.18**	**1.37**
Guidance		***$0.90-$1.00***	***$0.95-$1.05***			
Consensus			1.03	1.11	1.17	

Source: Company Filings, FactSet, and UBS Estimates

Synergies and lower financing requirements help us arrive at accretion next year.

Synergies are expected to be $20Mn at NMGC for reduce overhead (headcount, audit, etc.) with half shared with customers via rate credits and the other half retained. Additionally, there are savings anticipated back at the Florida utility over time; we discuss synergies in greater detail in our 2Q14 earnings note '8/1/14 Synergy Step-Up'. We do not expect management to clearly delineate dollar financial synergy targets but we do look for TECO to discuss some of the key business drivers at EEI. The company is in a rate stay-out until 2018 and if management is able to achieve its synergy targets and have revenue growth materialize (1.25% customer growth in 2013 although we understand this has slowed a bit lately) they may be able to push-out a ratecase here for longer.

Figure 202: New Mexico Gas Company Accretion Calculation

New Mexico Gas Co. (Dilution)/Accretion Calculation	2013E	2014E	2015E	2016E
Pre-Acquisition (TECO Legacy)				
Net Income	$204	$217	$237	$254
Shares	216	216	216	216
EPS	**$0.95**	**$1.01**	**$1.10**	**$1.18**
Post-Acquisition (TECO + NMGC)				
Legacy Net Income	$204	$217	$237	$254
Contribution from NMGC (40% in '14)	$0	$7	$22	$26
Net Income Combined	$204	$224	$259	$280
Legacy Shares Outstanding	216	216	216	216
Shares Issued (At $18.10)	0	16.7	16.7	16.7
Weighted Average Shares Outstanding	216	223	233	233
EPS combined	**$0.95**	**$1.00**	**$1.11**	**$1.20**
NMGC Deal now appears accretive w./ less equity issuance				
Change in EPS	**$0.00**	**($0.00)**	**$0.02**	**$0.03**

Source: Company Filings and UBS Estimates

With the ink barely dry on New Mexico, we ask management whats next?

TECO is focused on successfully integrating the New Mexico deal and delivering on the accretion goal for FY15; however, the company would be interested in additional M&A. What criteria does management look for?

- **Prefer gas over electric opportunities:** Management believes that gas utilities are viewed more favorably by investors although commented that there are fewer opportunities for acquisitions on the gas side versus electric

- **Be of a size that TECO can handle:** The $950Mn NMGC is an example of a modest relative size (TE current market cap is ~$4Bn). **We discussed the opportunity for M&A involving PNM Resources recently** following media reports on The Deal but we do not see TECO as a likely acquirer with its recent New Mexico acquisition so fresh in regulators minds. The opportunity exists to do some 'bolt-on' smaller acquisitions in New Mexico but we believe TECO would prefer to let things settle in the state and avoid culture shock following the prolonged regulatory approval process. The ~$2Bn market cap PNM would be a decent fit as it would allow management to leverage its existing knowledge base in the state but just not at this time.

Acquisition should not be too big or too small – looking for 'just right'.

- **Have a favorable geography:** The Company has discussed in the past that it has a 'sunbelt' strategy where it wants to remain below the middle of the country where there is above-average growth. Additionally, TECO ranks a favorable regulatory environment high on its list of preferences.

Continuing to Monitor Gas Ratebasing

TECO is watching the proceedings with NextEra Energy's Florida Power & Light sub (FPL) but appears hesitant to follow NEE's path. TECO's capacity is ~60% gas-fired although that will increase when Polk is on-line but the need to diversify the fuel-mix is not as high as it is for FPL. For further details please refer our July note on NextEra. While management has not made a definitive statement in support of it, we would believe that TECO would attempt to pursue gas rating basing, even if in very small scale, if NextEra is successful and well received at the Florida PSC.

TECO is taking a 'wait-and-see' approach to gas ratebasing.

Risk around Florida PSC appointments declining

With Commissioners Balbis' and Brown's terms expiring at the end of this year and the remaining three Commissioners having terms extending through 2016-2018, Governor Scott's nomination process is currently underway, with 16 candidates recently interviewed for the two opening spots. Our impression is that none of the 16 candidates would be objectionable to the state's utilities. This is important in that should Crist win the election, he may reject Scott's final picks, but may only replace them with the other candidates already approved by the Florida Public Service Commission Nominating Council unless he receives legislative approval for a new nominating process – unlikely to be given by a still deeply Republican legislature that is largely antipathetic to Crist's recent "conversion" to the Democratic party in December 2012. In any event, we believe that a silver lining of a Crist administration could come in the form of a stronger emphasis on (ratebase-eligible) solar initiatives that have been sidelined on economic concerns by Scott.

Handling the regulatory relationship in Florida

As we discussed in our recent note following the Democratic primary, a victory by Democrat Crist over incumbent Governor Scott (R) will be perceived negatively for NextEra's FPL and TECO's local utilities given previous interactions with the regulated entities. It does not appear to be a secret that the business community is more supportive of Scott but the potential impact of Crist winning is an unknown.

With New Mexico in the bag, what about the dividend?

We estimate that TECO's consolidated payout ratio will decline from 93% in 2013 to 79% in 2015E and 74% in 2016E. The dividend has remained at $0.88/sh since 2012 (although the cash payout will increase notably by ~$15Mn/year following the equity offering) and do not anticipate the dividend increasing next year given the payout ratio still remaining well-above peers.

We do not anticipate a dividend increase for 2015 with the payout ratio still estimated to be around 80%.

Valuation: Maintain $17 Price Target

Following the NMGC deal closing we have rolled-forward our valuation to 2016 where we see stronger fundamental but maintain our $17 Price Target. The big wildcard is the realizable value of TECO Coal. We calculate an implied 2016 P/E of 14.7x with Coal generating insignificant EPS and the parent drag, a slight premium to the group.

Figure 203: Updated TECO Valuation

			Ute + EV/EBITDA		Ute + Reserves	
Business Segment	**Valuation Metric**	**2016E $MN NI**	**Valuation Multiple**	**($s MM) Value**	**Valuation Multiple**	**($s MM) Value**
			Peer Multiple	14.5x		
Regulated Business		**Premium**	0.50x	**P/E**		**P/E**
Tampa Electric & Peoples Gas	EPS	$282	15.0x	$4,236	15.0x	$4,236
TECO Franchise Regulated $/sh				**$18.21**		**$18.21**
Unregulated Business				**EV / EBITDA**		**Reserves - $/ton**
Coal	EBITDA	$41	4.5x	**$186**		**$298**
$/share				$0.80		$1.28
Total TECO Asset Value				**$205**		**$316**
Projected Parent Debt				1,041		1,041
Less: Cash Balance (2015E)				249		249
Parent Net Debt	**Reflecting latest TE Coal**			792		792
Parent Net Equity Value	**disclosures - below book value**			**($587)**		**($476)**
TE Standalone Equity Value				**$3,649**		**$3,761**
New Mexico Gas	EPS	$26	15.5x	$403		$403
New Mexico Gas $/sh				**$1.73**		**$1.73**
Fully Diluted Outstanding Shares Reflecting NMGC Issuance (2016E)				233		233
TE Equity Value per Share				**$17.42**		**$17.90**
2016 Consolidated Earnings per Share				**$1.19**		**$1.11**
Implied P/E on 2016 Consolidated EPS				*14.7x*		*16.1x*

Source: Company Filings, FactSet and UBS Estimates

Westar Energy (Buy; $39)

In-line quarter; not likely to give 2015 guidance due to next year's ratecase

We expect Westar to report inline results **$1.07** vs consensus $1.08, with 6% milder weather about a penny above last year's also mild summer. The quarter benefits from +$0.04 higher rates from the LaCygne abbreviated ratecase increase of $31M that began in Dec 2013. This covers half the ratebase associated with scrubbers there, with the other half intended to be placed into ratebase in the next filing coming up on March 2. A transmission formula rate increase of $44M in Jan helps another nickel, while the environmental cost recovery rider (ECRR) stepped up another $11M in June, boosting a penny. Increased O&M of $23M this year (excluding the $9M Wolf Creek outage in Mar/Apr) reduces EPS by -$0.03. As discussed in the 2Q call, the company had already booked $6.5M of COLI in 3Q14 vs $7.5M in 3Q13 (none in 4Q13); this will result in a penny reduction to EPS yoy. Dilution from settling the equity forward sale reduces earnings -$0.03 for the quarter, with about 1.2M shares settled in 3Q14, to be followed by another 1.2M in 4Q and the remaining 8.9M in May/June 2015. Notably, the final lump settlement will take place after the March 2 ratecase filing, which will necessitate a follow-on adjustment filing to the cap structure after that occurs. Ultimately, management still expects the ratecase to be based on a ~52% equity ratio.

With rates from the upcoming ratecase in effect in November, we also do not expect any imitation of 2015 guidance this year beyond general factors that will probably be provided at EEI.

With TTM at $2.31 based on our 3Q estimate of $1.07, we do not expect any change to management guidance of $2.30-$2.45 (vs UBSe and consensus $2.38). With rates from the upcoming ratecase in effect in November, we also do not expect any initiation of 2015 guidance this year beyond general factors that will probably be provided at EEI. Our estimates and $39 PT remain unchanged and we reiterate our Buy rating predicated on a high and stead-growth transmission thesis. We do not believe any serious harm has come to the company's regulatory relationships or their ability to earn full FERC transmission returns (see discussion below).

Our estimates and $39 PT remain unchanged and we reiterate our Buy rating predicated on a high and stead-growth transmission thesis. We do not believe any serious harm has come to the company's regulatory relationships or their ability to earn full FERC transmission returns (see discussion below).

Figure 204: WR 3Q Walk

3Q14 Earnings Walk	EPS
3Q13A Adjusted EPS	**$1.04**
Weather Reversal from 3Q13	$0.02
Weather Vs. Normal	($0.01)
LaCygne Abbrev ratecase	$0.04
Transmission Rates	$0.05
ECRR	$0.01
Opex	($0.03)
D&A	($0.01)
AFUDC	$0.00
Interest Expense	($0.01)
Share Dilution	($0.03)
COLI	($0.01)
3Q14 UBSe	**$1.07**
Consensus	*$1.08*
2014 Guidance	*2.30-2.45*

Source: UBS Estimates, Company filings, FactSet

WR has filed ~300 project proposals with SPP to stake competitive territory

Making up almost 25% of all proposals, the projects are part of SPP's competitive transmission solicitation under its new FERC 1000 tariff compliance. We expect the RTO to announce a list of proposed competitive and incumbent (non-competitive) projects by December (rather than October as had been the previous expectation), still in time for consideration before the January 2015 SPP board meeting. The process is moving a little slower than expected as SPP would like to avoid the issues seen with PJM's Artificial Island process. Nevertheless, final winners are still expected to be announced next summer. We think SPP could yet emerge as among the more 'competitive' frameworks, giving WR a running start on what is likely to be the underpinning of continued growth late in the decade. Importantly, none of the proposals are included in its current long-term capex forecast.

The process is moving a little slower than expected as SPP would like to avoid the issues seen with PJM's Artificial Island process.

Section 206 complaint does not concern us

After reviewing the Kansas Corporation Commission's (KCC) Section 206 transmission formula rate complaint, we reiterate our Buy rating that is largely predicated on a robust long-term transmission investment growth rate. We are convinced that the KCC faces long odds of success in their attempt to convince FERC to adjust their methodology so soon after the resolution of the New England case in order to produce a base ROE radically lower than the 10.56% set for New England. Moreover, FERC specifically advised that evidence and analyses provided in other complaints be "guided" by the New England outcome. Comments were due on Sept 29th, after which a possible settlement phase could begin once an ALJ is assigned, perhaps in November. We do not expect a conclusion until 2015 at least.

The recent challenge does not shake our confidence in the long-term transmission story.

While WR's current base ROE of 10.8% plus a 50 bps adder for SPP RTO is above FERC's 10.56% upper-half midpoint, it is still well within the 9.39%-11.74% zone of reasonableness and unlikely to be changed significantly, in our view. In contrast, the KCC cites 8.87% base plus 50 bps as more reasonable based on its adjusted calculations using the FERC two-step method. In our opinion, a reduction of 169 bps is unlikely to be considered consistent with FERC guidance. It is our impression that WR did not file a Section 205 complaint (as requested informally by the KCC) in order to avoid opening the issue up to other parties. Furthermore, while a Section 205 filing need only show that proposed rates are just and reasonable, a Section 206 must also meet the higher burden of proof that existing rates are unjust and unreasonable as well.

Challenge could be an uphill battle for the KCC

We believe that the KCC request reflects the testing of FERC rates generally throughout the nation and is not necessarily a reflection of a serious deterioration of their regulatory relationship with WR. The utility's current Kansas jurisdiction authorized ROE is 10.4% and as noted in the complaint, WR and the KCC both agreed recently to voluntarily reduce the ROE component of its Generation Formula Rate from 10.8% to 10.2%. With trailing 12 month overall ROE at a healthy 9.8% (9.5% for Kansas jurisdictional assets), we still expect WR to file its next Kansas ratecase in March or April 2015 in order to place the remaining portion of LaCygne scrubbers into ratebase. While the settlement of equity forward sales (~3M shares in 2H14 and another 8.9M shares in mid-2015) will flow into the average shares outstanding through mid-2015, note that no further market sales of equity are required through this time. The dividend currently stands at the low-end of their payout target 60%-75% and will probably remain there

through the next ratecase (in a test year now). The earliest a dividend step-up would probably occur is Feb 2016.

Deferral application for La Cygne depreciation approved

The deferral helps to create a 'smooth' EPS growth trajectory

A joint application with co-owner GXP for a construction accounting order for the La Cygne retrofit rate case has been approved by the Kansas Corporation Commission (KCC). Westar will be able to defer about 5 months of depreciation expense (and continue to book carrying charges) next year after the scrubbers are in service, but while awaiting a final rate order at the end of the year. The deferral is expected to drive EPS up ~$0.10 in 2015, including $15M of depreciation and another $5.5M of related carrying costs (already baked into our estimates).

While this improvement is essentially a one-time item with little effect on our 2016 estimate (which already has recovery of depreciation post-ratecase), we believe it highlights the effect of management's efforts to minimize regulatory lag through its fundamentally excellent working relationship with regulators, which we believe remains in-tact despite the Section 206 complaint described above.

Sales growth projection of 50-100 bps for 2014 likely conservative

Despite 2.1% growth in 1Q14 YoY industrial MWh sales, WR has maintained its 2014 projection of 50-100 bps retail sales growth, but says it could be at the high end of the range or above it due to strong economic trends. In recent months, the company has noted a levelling off of previously declining usage patterns and some increasing signs of optimism from its industrial customer base - in particular, the local aerospace industry (orders for business aircraft still 18-24 months away though). Kansas unemployment remains below the national average at only 4.9% and we believe WR's sales forecast is deliberately conservative in the face of improving trends. Residential sales growth is even beginning to look somewhat better over the longer term.

Ratecase strategy remains unchanged

Keeping the ROE gap limited.

With trailing 12 month overall ROE at a healthy 9.8% (9.5% for Kansas jurisdictional assets), WR will file its next ratecase on March 2 in order to place the remaining portion of LaCygne scrubbers into ratebase. Staff and intervenor testimony are scheduled for early July with a final order on Oct 28 and rates in effect in November. WR has reached settlements in the last two GRCs and would generally prefer to settle cases (although even in an early settlement, the Nov implementation date would remain).

WR has reached settlements in the last two GRCs and would generally prefer to settle cases

While the settlement of equity forward sales (~2.4M shares in 2H14 and another 8.9M shares in mid-2015) will flow into the average shares outstanding through mid-2015, note that no further market sales of equity are required through this time. The dividend currently stands at the low-end of their payout target 60%-75% and will probably remain there through the next ratecase (in a test year now). The earliest a dividend growth step-up would probably occur is Feb 2016 (the usual Board decision timeframe).

Wisconsin Energy (Neutral; $44 PT)

Quarter should still come in ahead of guidance despite the cold. Aside from more color on TEG progress, look for more details on ATC and potential standalone growth avenues.

Management could give up the ~$0.09 of positive first quarter weather due to 30%+ decline in CDDs.

We estimate that WEC will report adjusted EPS of **$0.51**, a penny ahead of consensus at the high-end of management's (typically) conservative guidance range $0.48-0.50. As a reminder, WEC has beaten consensus earnings expectations for 18 consecutive quarters dating back to 4Q09 although the extreme relative cold this summer could put that risk at more jeopardy than usual. We expect an exceptionally mild weather to have an adverse impact of about $0.09 to 3Q. Management has highlighted a 44% decline for July Cooling Degree Days compared to 20 year average (and ~25% lower for each of August and September) – and not a single 90 degree summer over the entire summer over its service area. Lake Michigan, which set a record for ice cover on March 8 this year (recording a ~93.3% ice cover), and the lake effect held much longer than usual. Despite the cold weather there is no offset from the ~50% increase in September HDDs as customers did not use much gas during the period. We also include a $0.02 O&M hit in 3Q as management stated on its 2Q call that O&M for 2014 will be back end loaded in H2.

FY14 guidance could still be increased a couple of pennies despite the sharply lower earnings in 3Q.

With our initial expectations for a flat 4Q14, our TTM/FY14 adjusted EPS of $2.63 remains at the high-end of the FY guidance range ($2.58-$2.63) so management could lift its range slightly to **$2.60-$2.66**. Although the TEG deal will not close until July 2015, we think management will continue their practice of giving their full year forward year guidance on the 4Q call in February – but for WEC standalone. We then expect them to revise full year combined earnings after deal closure.

Figure 205: WEC 3Q14 Earnings Walk

3Q14 Earnings Walk	EPS
3Q13 Adjusted EPS	$0.60
Return to Normal Weather from 3Q13	$0.00
Weather in 3Q14 - Unseasonably Cold	($0.09)
Normalized Grant Income for Biomass	$0.04
Rate Increase from Case (Higher Elec/Lower Gas)	$0.00
Presque Isle SSR payments (Earnings Neutral)	$0.00
O&M - Higher in 2H due to timing	($0.02)
D&A	($0.02)
ATC Transmission YoY	$0.00
Interest Expense	($0.01)
Impact of Buybacks	$0.00
3Q14 Adjusted EPS	**0.51**
3Q14 Consensus	***0.50***
3Q14 Guidance	***0.48-0.50***
2014 Guidance	***2.58-2.64***

Source: Company Filings, FactSet and UBS Estimates

Links to our relevant recent research are below:

8/26/14 Power Points: WEC/TEG Latest Guidance (P12)
8/1/14 Polar Vortex, Summer Edition
6/26/14 TEG-Tie: Upgrade to Neutral on Deal Accretion

TEG acquisition on target for summer close, or earlier

All regulatory filing for the deal have now been made (WEC and TEG filed the S-4 with the SEC in August). Management has scheduled a shareholder meeting on Friday, November 21st – to be held in Milwaukee by WEC and in Chicago by TEG. In the meanwhile, the regulatory process is ongoing as expected. Management expects decisions to be made in various states at dates highlighted in the table below. Minnesota may eventually choose to not have any hearings given that the target utility (TEG's Minnesota Energy Resources) is a smaller player in the state; TEG's local gas utility has $193Mn of ratebase and 216,000 customers as of 12/31/13.

Deal could take as long as July to close but IL is the longest dated jurisdiction.

Figure 206: Expected dates by which states should rule

State	Expected decision by
Wisconsin	Mar-15
Illinois	Jul-15
Michigan	Feb-15
Minnesota	May decide to not have hearings given small rate base exposure

Source: Company sources

We think that the deal is online for the expected summer 2015 closure. Other than key regulatory dates over the next few months, we do not expect any other material updates by management on the 3Q call.

Our own analysis continues to show the acquisition a strong strategic fit for WEC, given the existing transmission relationship, ownership of American Transmission Company (ATC), and the ability to merge a high-growth entity with a robust FCF generator, driving no incremental equity needs to deliver its targeted growth.

Using data points from the S-4 filing, we forecast that the transaction will have an accretive EPS impact of $0.15 in 2016, declining less than a penny on ~$1Mn lower Integrys income estimates. Given the deal is expected to close by summer of 2015, our 2015 accretion is illustrative. Additionally, 2014E income appears inflated by the sale of Integrys Energy Services to Exelon for $243Mn.

We highlight that Integrys has already said that there were risks that the company stand-alone may not achieve its growth targets – in fact this was seemingly one of the drivers for the transaction from TEG's perspective – but at this stage we rely upon TEG's guidance in our accretion math.

We do not model planned dividend increases yet

WEC has said it plans to raise the dividend twice in 2015 a total of 14%-15%. This will include the planned WEC increase of 7%-8% in January followed by another 7%-8% rise after the TEG merger closing in order to keep TEG shareholder's dividend in-tact. Going forward in 2016+, the combined company dividend policy is expected to be accretive to both sets of shareholders. Our estimates do not yet incorporate either the merger or the second dividend increase next year. Mgmt maintains a 65-70% payout target by 2017, however, the double-jump could drive an acceleration of this level into 2016.

What about EPS growth rate? We see some upside

We re-include WEC's recently filed S4 filing around its transaction to illustrate its own projections of medium-term EPS growth of just shy of 4%, the bottom end of its target.

Figure 207: Looking at the S1 Filing for Clues on WEC's Growth – Stand-Alone and Combined.

Mangement's Base Case in S-4	2014	2015	2016	2017	2018
EBITDA	1,553	1,548	1,693	1,761	1,799
Net Income	596	611	648	675	691
UBS Net Income estimates	597	605	624	640	650
Management's EPS	*2.62*	*2.68*	*2.85*	*2.97*	*3.04*
Growth Rate		*2.5%*	*6.1%*	*4.2%*	*2.4%*
4-Year CAGR					*3.8%*
UBS EPS estimates	*2.63*	*2.66*	*2.76*	*2.84*	*2.90*
Street EPS consensus	*2.62*	*2.7*	*2.84*	*2.96*	
Management's Adjusted Case in S-4	**2014**	**2015**	**2016**	**2017**	**2018**
EBITDA	1,677	1,642	1,795	1,891	1,936
Net Income	597	581	621	647	665
Mangement's adjusted case EPS	2.62	2.55	2.73	2.84	2.92
Growth Rate		*-2.7%*	*6.9%*	*4.2%*	*2.8%*
4-Year CAGR					*2.7%*

Source: Company reports and UBS estimates

Combining the Filings with Integrys S4, we find a different outlook

When combining the outlook with Integrys' S4 filing of Net Income, we find the potential to add up +2% of growth on our projections (without corresponding equity). **Given WEC's historic ability to avoid equity, we see credibility to at least hitting the midpoint of its higher 5-7% EPS growth range (vs. 4-6% previously)**; specifically, the projections below are prior to embedding any synergy benefits derived from the deal (largely to be given back to consumers in any event, seeing the company's as largely hitting their ROEs).

We think there is upside on medium-term growth rate

Projections indicate WEC is at the top-end of 4-6% target

Figure 208: Integrating the TEG Outlook to Come up ahead on growth

Integrys Base case in S-4	2013	2014	2015	2016	2017	2018
EBITDA		912	932	1,032	1,074	1,204
Net Income		435	294	328	337	386
Growth Rate				12%	3%	15%
Total WEC + TEG Net Income from S4		**1,031**	**905**	**976**	**1,012**	**1,077**
Growth Rate				**7.8%**	**3.7%**	**6.4%**
						6.0%
EPS contribution on combined entity		*1.38*	*0.93*	*1.04*	*1.07*	*1.22*

Source: Company filings and UBS estimates

But what about div growth? Double jump in '15 and then normalizes

We look for a further meaningful jump (likely in 7-8% in December/January), alongside a further ~6-7% increase to get WEC's dividend inline with TEG. While not likely, this only further reiterates our point that net income growth projected in the S4 will *not* be diluted by subsequent equity issuance.

Figure 209: Dividend Increase – How much in 2015?

Dividend Increase Math for 2015	
WEC Dividend	1.56
TEG/WEC Exchange Offer	1.128
Multiply Dividend by Exchange Ratio	1.75968
Div Yield Implied on Shares using WEC Div Rate	3.48%
Dividend Yield Today	3.93%
Div Increase Necessary	**13%**

Source: Company reports and UBS estimates

ATC Capex update yields significant uplift

We reflect the latest American Transmission Company (ATC) 10-year capex plan, updated late last week. We flag that the latest update is amongst the most significant upward revisions in recent years, seemingly on the back of the Presque Isle.

Figure 210: ATC – 10-Year Capex Plans ($Bn)

Transmission Investments ($B)	2010	2011	2012	2013	2014E
Specific Network Projects	1.0	1.0	1.9	1.2	1.4
Regional Multi-Value Projects	0.7	0.7	0.8	0.5	0.5
Asset Maintenance	0.7	1.0	1.1	1.1	1.2
Other Capital Categories	1.0	1.1-1.7	0.1-1.0	0.2-0.8	0.2-0.8
Total 10-Year Capital Cost	3.4	3.8-4.4	3.9-4.8	3.0-3.6	3.3-3.9

Source: Company reports and UBS estimates

REIT unlikely for ATC any time soon

WEC will opt for conservatism, as usual.

After the acquisition of TEG, the combined entity will have ~60% ownership of ATC – a transmission company with more than $3bn in rate base. Although we reiterate that we think this gives WEC the choice to form a REIT with ATC's transmission assets, we highlight that management continues to downplay any such eventuality. Management has said that they will not keen to be "first movers" in attempting to experiment with a REIT or YieldCo structure for transmission assets. Regardless, we do think that WEC management would likely not truly consider such a corporate structure change ahead of the closing of the TEG acquisition anyway.

Wisconsin asset sales – election results are key

What could happen to Wisconsin's "Crown Jewels"? Not much in 2014 it looks like.

Gubernatorial elections are due in Wisconsin in the first week of November. If the incumbent Republican Scott Walker retains his position as Governor, we think privatization initiatives will go ahead. However, we think the plans may be shelved in case the Democratic candidate Mary Burke wins. Media reports suggest that the race is a very close one.

Are there other interested parties in the assets? *Possibly*, but operator experience matters.

Nonetheless, should anything happen, it will only be in 2015 at the earliest. We do highlight however, that WEC has formed a 50/50 JV with MGE Energy (called State Energy Services) to evaluate potential bids for the possible sale of state-owned cogeneration facilities, should they happen. The possible portfolio which may be up for sale includes the 150-MW University of Wisconsin West Campus Cogeneration Facility built in 2005 for $190M as well as numerous other cogen

plants located on state-owned property including prisons and other campuses. MGE Energy already owns 50% of the West Campus plant and operates it.

We expect that should the sale happen, it would probably be financed in a way similar to WEC's Power the Future, with a long-term fixed-ROE contracts outside of ratebase that could last 20 years or more (but with a lower ROE in the ~10% range). We also note that many of the plants have likely been out of environmental compliance and would almost certainly need significant scrubber upgrades. Conversion to gas is probably a non-starter too as the plants are used for steam heating as well as electricity. While there has been no official cost estimate, we note that at times, unofficial numbers have been thrown around in the press in the neighborhood of $200-$250M.

Ratebase opportunity could be worth up to ~$1/sh.

More specifically, the Wisconsin budget grants the Building Commission with the authority to sell or lease state buildings (albeit with restrictions), subject to the approval of the Joint Committee on Finance. Currently the state is still in the process of retaining an advisor to oversee the process but it does not appear that significant progress has been made recently although selecting an advisor is certainly a step in the right direction.

Additionally with competition for the assets among regional peers, a JV makes sense as it was always unclear if WEC could be awarded all of the investment, at best representing ~$0.06 in EPS as calculated below ($0.03 under a 50% JV). 'Ratebasing' these assets appears unlikely, but pre-arranged sales & PPA agreements back to the state will provide regulated-like returns. We look for more concrete details in the upcoming three-to-six months, as negotiation and RFP get under way.

Figure 211: Potential EPS from WI Privatization if Ratebased

Wisconsin Privation Potential EPS	
Capex ($Mn)	$250
WI ROE	10.40%
Midpoint WI Equity Ratio	51%
Potential Earnings	13.26
Shares (2015E)	228.50
Potential EPS	$0.06

Source: Company Filings and UBS Estimates

Presque Isle: Michigan PSC opposes proposal to create two balancing authorities

Michigan gets the benefit of the SSR payments while Wisconsin had been bearing the burden. But no longer.

Wisconsin Energy has proposed to create two Balancing Authorities (BA) which would separate out the Upper Peninsula, effectively addressing the cost sharing issue between the two regions for the Presque Isle plant. The Michigan PSC argues that WEPCo's proposal to create two new BAs would result in the System Support Resource (SSR) costs being borne by Michigan customers "as high as 99%" versus 14% Michigan/86% Wisconsin previously. The Michigan PSC opposes the proposal on operational grounds (that the cost shift is "so grossly unjust and unreasonable") as well as procedural (lack of proper notice). Docket EL14-104.

Earlier this summer the FERC ruled in favor of WEC customers who had complained about $26M of costs related to out-of-market System Support Resource (SSR) payments made to keep the Michigan-based Presque Isle plant running for reliability. FERC agreed that the reliability benefits accrued to Michigan customers rather than Wisconsin ratepayers, who had been responsible thus far due to a quirk of MISO rules and the location of the plant within American Transmission Company's (ATC) footprint. The ruling will have no direct effect on WEC earnings (just who pays). With the recent Presque Isle RFP process drawing little/no bidding interest, we expect either a sale of the plant for negligible value, or early retirement (due to EPA rules) given the shopping of regional load. While the plant illustrates the issue with customer choice in Michigan, we remain focused on the transmission opportunities for ATC and ITC on the back of any eventual retirement.

The ruling will have no direct effect on WEC earnings (just who pays).

Capital cost for MATS compliance on all five units is expected to be in the range of $6-12Mn if required to utilize dry sorbent injection (DSI) with the expectation that any environmental capex would be recoverable, just as the aforementioned SSR payments, as a requirement to operate the plant.

An interesting wrinkle in the entire Presque Isle debate relates to WEC's acquisition of Integrys as the cause of the SSR payments in the first place was the lost load when the local mining customers switched from WEC to Integrys. If and how this impacts the ultimate fate of the plant remains to be seen.

Will TEG acquisition impact the outcome for Presque Isle?

MISO proposes to double payments to Presque Isle to ensure reliability into the Upper Peninsula

MISO has proposed that the existing $4Mn per month payment that it makes to Presque Isle be increased to $8Mn per month when the contract is renegotiated after expiring in February 2015. The new contract would be for 14.5 months, and is intended to cover for emissions control costs (discussed above) which will be required at the plant to comply with MATS and EPA rules. MISO has highlighted that given other pending closures and resultant tight capacity – compounded by transmission bottlenecks into the Upper Peninsula - closure of the plant may be catastrophic for the regions power supply. Meanwhile ATC has said that it estimates $3.3-3.9bn of transmission investments over the next 10 years in the broader region to ensure grid reliability – before the expected 2014-19 project completion dates for these projects, Presque Isle may be required to keep running to ensure power supply into the Upper Peninsula.

Valley Power and Twin Falls still on track

The 280-MW Valley Power cogeneration coal-to-gas conversion project remains on schedule to finish the conversion of Unit 1 boiler in 2014 followed by Unit 2 in 2015 at a cost of $65-$70M excluding AFUDC. A related $30M pipeline connector upgrade is on time and on budget as well. It appears that the exceptionally mild weather and also the difficulties in coal procurement have not had any negative impact on these tests.

The $60-$65M Twin Falls hydro upgrade to build a new powerhouse and add spillway capacity is also on track, with major construction begun and a completion date later this year for operation in 2015.

Management has said that tests using a blend of bituminous and PRB coals at Oak Creek have so far been promising (the company had received approvals to carry

out these tests in May 2013). Given cost differentiation between the two, the company estimates that blending the two kinds of fuels can bring savings of $25-$50mn to consumers. The company has already received environmental permits, and has filed a request with the Wisconsin Commission to approve $25mn additional capital spending for modifications at the plant that would allow testing of up to 100% PRB. However, for the plant to operate at more than 20% PRB on a sustained basis, additional capital spending would be required to expand fuel handling and storage.

Coal inventories improving

While access to coal has been an issue for many this summer given rail bottlenecks, WEC has not seen experienced material issues given its access to eastern and western coal. Additionally, there has not impacted the company's ability to procure both for its fuel blending tests.

Xcel Energy (Neutral; $30)

Nickel miss on mild weather; 2015 guidance could be pushed to EEI

We expect 2015 guidance to be about 5% above current 2014 guidance, or $2.00-$2.15, in-line with UBSe and consensus $2.09.

We expect XEL to report 3Q **$0.75** vs consensus $0.80 and last year's $0.77. Last year's 3Q was boosted by +$0.05 of favorable weather, and this year has been a mild one, with 36% less CDD in Minnesota in July and 25% less CDDs in August in Colorado. Texas has been more of a mixed bag this summer; more or less normal overall. We expect a -$0.07 year over year impact from weather overall. Sales growth (weather norm) helps a penny, with each 100 bps of growth worth $30-$40M pretax annually on the electric side and another $6M at the gas utility. The interim rate increase in Minnesota has a net $107M impact on EPS, or about $0.04 for the quarter, with 3Q responsible for 27%-28% of annual revenues. Other rate increases in ND, WI, CO, TX, and NM add to +$0.03 together. A $45M increase in capital rider revenue helps +$0.02 but this is offset by -$0.02 higher O&M. Depreciation, Interest, Prop taxes, and AFUDC add to -$0.02, although the company's income tax rate has been in the 34%-36% range for the past year with no incremental impact. Dilution reduces a penny.

With management guidance of 4%-6% growth, we expect 2015 guidance to be about 5% above current 2014 guidance, or $2.00-$2.15 with the midpoint $2.07 in line with UBSe and consensus $2.09.

Normally the company would initiate 2015 guidance on the 3Q call. But given the still ongoing Minnesota ratecase, the company may wait a little longer toward EEI or beyond to provide it this year. Reply briefs are due Oct 14, followed by an ALJ recommendation Dec 22 and a final decision due in March 2015. **With management guidance of 4%-6% growth, we expect 2015 guidance to be about 5% above current 2014 guidance, or $2.00-$2.15 with the midpoint $2.07 in line with UBSe and consensus $2.09.**

Figure 212: XEL 3Q Walk

XEL 3Q14 EPS Walk	
3Q13 EPS	$0.77
Weather Normal	($0.05)
Milder than Normal Weather	($0.02)
Sales Guidance (+1.0% elec, +2% gas)	$0.01
Rate Cases	
Minnesota (effective Jan 2014)	$0.04
ND Step Increase 9.4M (May 2014)	$0.00
WI, electric (19.5M effective Jan 2014)	$0.01
CO-electric (25M yr-3 plan stepup effective Jan 20	$0.01
CO-gas (effective Aug 2013)	$0.00
TX Stepup (effective September 2013)	$0.00
NM ($12.7M effective April 2014)	$0.00
Capital Rider Revenue ($45M increase)	$0.02
O&M (2-3% growth in 2014)	($0.02)
Depreciation (30-40 increase)	($0.01)
Interest Expense (5-15 *decrease*)	$0.00
Property Taxes (40-50 increase)	($0.01)
AFUDC (5-10 increase)	$0.00
Increased taxes (to normal 34%-36%)	$0.00
Dilution	($0.01)
3Q14 EPS	0.75
Consensus	*0.80*
2014 Earnings guidance	*$1.90 - $2.05*

Source: UBS estimates, Company filings, FactSet

Figure 213: XEL Estimates, 2013A-2018E

UBS Estimates ($/share)	2014E	2015E	2016E	2017E	2018E
PSCo	$0.94	$1.00	$1.04	$1.09	$1.14
NSPM	0.79	0.85	0.89	0.93	0.98
SPS	0.22	0.22	0.22	0.22	0.21
NSPW	0.13	0.14	0.16	0.17	0.18
XEL Parent	(0.11)	(0.12)	(0.12)	(0.13)	(0.13)
UBSe EPS	$1.98	$2.09	$2.19	$2.28	$2.39
CAGR				*4.9%*	*4.8%*
Guidance					*4-6%*
Previous Ests	$1.98	$2.09	$2.19	$2.28	$2.39
Consensus	$1.99	$2.09	$2.20	$2.35	$2.35

Source: UBS estimates, Company filings, FactSet

Maintain $30 PT.

Figure 214: XEL Price Target

BASE CASE			Low Case		Base Case			High Case	
Business Segment	**Valuation Metric**	**2015 EPS**	**Valuation Multiple**	**($/Share) Value**	**Premium/ Discount**	**Valuation Multiple**	**($/Share) Value**	**Valuation Multiple**	**($/Share) Value**
Regulated Business						**Regulated Peers:**	14.2x		
Northern States Power - Minnesota	P/E	$0.89	12.7x	$11.26	-1.0x	**13.2x**	$11.70	13.7x	$12.14
Northern States Power - Wisconsin	P/E	$0.16	14.7x	$2.36	1.0x	**15.2x**	$2.44	15.7x	$2.52
Public Service Colorado	P/E	$1.04	13.7x	$14.27	0.0x	**14.2x**	$14.79	14.7x	$15.31
Southwestern Power Service	P/E	$0.22	13.2x	$2.92	-0.5x	**13.7x**	$3.04	14.2x	$3.15
HoldCo									
Parent & Other Overhead Expense	P/E	($0.12)	13.7x	($1.70)		14.2x	($1.76)	14.7x	($1.83)
XEL Equity Value per Share		**$2.19**		**$29.11**			**$30.21**		**$31.30**

Source: UBS estimates, Company filings, FactSet

Most Recent Updates: Transcos, Ratecases, Black Dog Hibernating

Transcos: XEL has made FERC filings for both of its newly formed independent transmission companies, Xcel Energy Transmission Development Co, which will compete for projects in MISO (including Entergy's service territory), and Xcel Energy Southwest Transmission Co, which will compete in SPP. State affiliated interest filings have also been made for the MISO company and will be made shortly for SPP. Management has filed for a generic ROE in MISO of 12.38% (rather than company specific) and intends to lever these subsidiaries to 55%, as allowed by FERC. While the company is still considering the appropriate level of holding company debt, we would ultimately expect Xcel to follow the lead of ITC and likely AEP by utilizing back-leverage at the parent to further enhance returns greater than the already high leverage at the operating company level. We reiterate that none of these competitive projects are included in the company's current $4.5B, 5-year capital plan, although some projects at OpCo appear they could yet shift to TransCo.

Minnesota and Monticello: Hearings in the Monticello prudency case begin Sept 29-Oct 3, followed by an ALJ decision that should dovetail with the NSP Minn ratecase, which has an ALJ sched for no later than Dec 22. The company hopes for earlier resolution than December and may delay 2015 guidance to EEI depending on the status of the case when 3Q earnings are released. Our worst-case Monticello outcome (max disallowance) would only impact earnings ~$0.03-$0.05.

Colorado: In Colorado, we still expect the case to be settled, but note that the procedural schedule calls for staff and intervenor testimony Nov 7, rebuttals Dec 17, Hearings Feb 26, and a final decision in March 2015. The company filed a new multi-year rate plan to begin next year. With the utility already earning above the auth 10% ROE (sharing with customers), management anticipates that the rate deficiency will be a modest ask, with most of it related to increased prop taxes and capital costs for the Clean Air, Clean Jobs project. XEL is also exploring the possibility of rate riders instead of a full-comprehensive multi-year rate plan (riders would be tax and environmental pass-through).

Texas: The SPS electric ratecase was settled, with interim rates as of Oct 1. Expect final approval by November. With a more liquid and less expensive emissions market in Texas, management continues to project no material impact from compliance with the Cross State Air Pollution Rules (CSAPR). Increased development of renewables and lower capacity factors for coal plants continue to drive a favorably low emissions market.

Black Dog Hibernating? XEL recently submitted comments to Colorado regulators regarding the All-Source RFP, revising the utility's need for new capacity and essentially arguing that no capacity need be procured under the RFP for the near future. With sluggish load growth, continued growth of solar and conservation, XEL will likely delay its integrated resource plan (IRP) past January. While the commission has yet to respond, we believe this likely pushes the Geronimo Energy Aurora Solar Project into the more competitive Solar RFP, despite the March ALJ recommendation in favor of it over XEL's Black Dog peaker and CPN's Mankato expansion. Both Black Dog and Mankato are likely to be delayed indefinitely.

Updated schedule:

- Aug 4 – Surrebuttal testimony, NSP MN electric ratecase – looking to see if bid/ask spread between NSP and the Dept of Commerce narrows (evidence of accommodation vs last year's hard line)
- Aug 11-18 Evidentiary Hearings, NSP MN electric ratecase
- Aug 26 – Rebuttal testimony for Monticello prudency case
- Sept 19 – Surrebuttal for Monticello prudency case
- Sept 29-Oct 3 – Hearings in Monticello prudency case
- Oct 3 – NSP Wisconsin intervenor test.
- Oct 17 - NSP Wisconsin rebuttal
- Oct 24 – NSP Wisconsin Surrebuttal
- Oct 28 NSP Wisconsin Hearings
- 4Q2014 – "Final" ruling on PPAs for Geronimo, Mankato, Black Dog
- Oct 14 - Reply brief, NSP MN electric ratecase
- Nov – SPS electric ratecase final approval of settlement at PUC
- Nov 7 – Colorado intervenor testimony
- Dec 17 – Colorado rebuttal
- Dec 22 – MN NSP ratecase ALJ recommendation
- Dec 31 – ALJ decision Monticello nuclear cost overrun prudence
- Dec 31 NSP Wisconsin Decision
- Feb 13 – Colorado interim rates
- Feb 26 – Colorado hearings

- 1Q15 – Final decision Monticello prudency
- Mar 2015 – Final decisions due MN NSP ratecase and Colorado ratecase

For further detail on these and other issues, please see our recent 8/4 note "**Catalysts Warming Up the Story**"

AES Corp. (Neutral; $15)

Despite quarterly beat, we are still at bottom-end of FY14 guidance range. Shares are looking more attractive at ~$13.20 but we remain on the sidelines.

We expect a slight beat vs. a wide consensus for 3Q results, at **$0.34 vs. Street at $0.32**. We think the focus will remain on capital allocation, as the latest EPS results will begin to more meaningfully feel the effects of the latest Masinloc sell-down (~$0.06 on FY basis). While F/X was not a concern YoY, the real focus will be hydrology as the headwind is anticipate dot *accelerate* in the back half of the year, as Tiete's contract position shifts to a net short one. We assume -$0.03 for the quarter, an accelerate vs. 1H impact of -$0.04, putting it on pace to see a -$0.10 impact for FY14.

Despite the beat, still at the very bottom end of guidance

As we look towards managements $1.30-1.38 2014 EPS guidance range, we anticipate even a strong showing this quarter will still results in management being at the very bottom end of its guidance range for the year. We are lowering our 2014 EPS estimate to $1.30, from $1.31 previously to reflect continued pressures – an dour lower 3Q estimate.

What do we think of shares from here? Looking more attractive.

We think shares are beginning to look more attractive, off their highs, however, remain on the sidelines given concerns on an emerging markets slowdown – and continued contracting issues in the medium term. We think capital allocation decisions will remain at the center of outperformance.

Figure 215: 3Q YoY Walk

3Q13A Adjusted EPS	0.39
Panama (Getting Better) /Brazil (Remains Weak) /Chile/Columbia Hydro	(0.03)
F/X (Primarily Brazil/Argentina) -- Flattish YoY	0.00
DP&L Switching (Continued, but slowing)	(0.01)
Normalized Tax Rate (26% Last Year vs. Low 30's Normal)	(0.01)
SG&A Savings (Continued Execution @ $5-10 Mn/qtr pace)	0.00
Capital Allocation - Share Repurchase (Executed in 2H13)	0.01
Jordan CCGT - 1st Quarter In-service for New CCGT Unit	0.00
Masinloc Sell-Down (mid-July) of 45% Stake to Local Partner	(0.02)
3Q14e Adjusted EPS UBSe	0.34
Consensus	*0.32*

Source: Company reports and UBS estimates

Contracting at Masinloc: The next big growth opportunity?

Following its sell down in 3Q to a local partner, we understand the company continues to negotiate multiple PPA offtakes for an expansion of this coal plant (300MW, but up to 600 MW) with parties. We believe any new addition would be viewed constructively, adding to long-term EPS growth.

Refinancing at DPL: retaining the commodity exposure in Ohio

In August AES had opted not to sell the GenCo portion of the DPL business, emphasizing that the value of the bids it had received were insufficient to provide a long-term path to recovery. In late September, the company successfully pushed out DPL's 2016 maturity debt with the issuance of new five-year paper. Had AES sold of DPL, it would have effectively locked the utility into its over-levered position. By deciding to not sell, and pushing out maturity via new debt issuance, AES has managed to extend the runway to see a potential commodities recovery by 2019.

The September refinancing deal involved a $200 Mn issuance and was coupled with ~$110Mn of cash on hand to pay down an aggregate $280Mn in debt tendered (with upside to ~$300 Mn of total debt paydown). As such, we see the remaining $130-150 Mn of the 2016 notes (vs. $430 Mn outstanding today), as readily able to be paid down with FCF generated in the interim (with room to spare to finance more pay down).

DPL Forecast

Improving FCF outlook at DPL and further cost cuts could go towards keeping the business in position to capitalize on commodity recovery.

We include our latest estimates, below. We project ~$400 Mn in FCF through 2016 (or ~$300 Mn through 2016 as of today's mark), emphasizing the ability to paydown the remaining 2016 at maturity (this is ahead of management's $200-300 cumulative FCF guidance at the subsidiary through the period).

But what about the long-term? DPL forecast is well below their goal

Our revised post-2017 estimate reflects additional cost-cuts to the GenCo (down to ~$50/kW-year in O&M on the coal business, at the lower end of our expectations), as well as some utility upside, on the back of a likely reinvigorated cost cutting effort (potentially as part of continued integration with AES' nearby utility subsidiary, IP&L in Indianapolis). Beyond these benefits, we emphasize management's aspirational guidance of ~$300-400 Mn in EBITDA for 2017+ seemingly reflects an expectation for either wider market recovery or a new regulatory revenue scheme (a la a PPA or ESP).

Figure 216: DPL Segment EPS and EBITDA – exposed to negative GenCO EPS 2016 and beyond

DPL Inc. Mini-Model	2012A	2013	2014	2015	2016	2017	2018	2019
T&D	175	175	175	175	175	180	186	191
DPL-ER - A	32	32	24	24	24	24	24	24
Generation (Energy Margin + Capacity) - B	(6)	(71)	1	62	26	56	94	123
ESP	75	75	110	110	110	0	0	0
Legacy Rates Benefit	116	72	45	18	-	-	-	-
Hedges (UBSe)	69	52	25	-	-	-	-	-
Switched (avg)	55.00%	40.00%	25.00%	5.00%	0.00%	0.00%	0.00%	0.00%
Legacy Book	12	12	12	12	12	12	12	12
Above Market ($/MWh)	35	30	30	30	30	30	30	30
Total EBITDA	460	335	355	389	335	260	304	338
Guidance				~350 through '16		*Goal is 300-400 beyond '16*		
Int. Exp	(123)	(124)	(117)	(107)	(98)	(92)	(86)	(76)
EPS	0.11	0.15	0.10	0.14	0.10	0.04	0.09	0.13
Interest Expense	123	124	117	107	98	92	86	76
Capex	198	124	136	124	133	129	131	130
FCF	139	87	102	158	104	39	87	132
Cumulative FCF ('14-'16)				365				
Cumulative FCF ('14-'16) - Guidance				200-300				
Project LT Debt	2,025	2,284	2,149	1,965	1,805	1,695	1,557	1,371
Debt/EBITDA	4.40x	6.81x	6.05x	5.05x	5.38x	6.51x	5.12x	4.05x
New Covenants under DPL Inc. notes	8.0x							
Genco Open EBITDA (w/ Retail) - A & B		(39)	25	86	50	80	118	147
GenCo D&A (est. on $1.5 Bn book value)			(60)	(60)	(60)	(60)	(60)	(60)
EBT (Assume No Debt)			(35)	26	(10)	20	58	87
Open AES GenCo EPS Contribution			(0.03)	0.02	(0.01)	0.02	0.06	0.09
UBS Prior (August 2014)			(0.03)	0.05	0.02	-	-	-

DP&L Summary	2014	2015	2016	2017	2018	2019
Utility EPS	0.04	0.04	0.04	0.04	0.04	0.04
HoldCo After-Tax Interest Drag Per Share	(0.06)	(0.06)	(0.06)	(0.06)	(0.06)	(0.06)
Non-Bypassable Transision Payment	0.11	0.11	0.11	-	-	-
GenCo EPS	(0.03)	0.02	(0.01)	0.02	0.06	0.09
Total DP&L EPS	0.05	0.11	0.08	(0.00)	0.04	0.07

Source: Company reports and UBS estimates

Latest Consolidated AES Projections, reflecting DPL estimate updates.

Figure 217: Updated AES Consolidated EPS Estimates

	2012	2013	2014	2015	2016	2017	2018
Consolidated EPS Projections	2012A	2013A	2014E	2015E	2016E	2017E	2018E
UBSe	1.24	1.29	1.30	1.33	1.46	1.58	1.79
Prior UBSe	*1.24*	*1.29*	*1.31*	*1.36*	*1.48*	*1.56*	*1.75*
Consensus		1.28	1.33	1.46	1.50	1.54	
Guidance		1.24-1.32	1.30-1.38	*"Low-End"*			
LT Implied Guidance - as of 4Q13 Call - LOW			1.30	1.35	1.35	1.43	1.52
LT Implied Guidance - as of 4Q13 Call - HIGH			1.38	1.46	1.51	1.63	1.76
Long-Term Growth Rate			4-6%		Flat-Modest	6-8%	LT Growth
DP&L Ex-Gen EPS (Utility + HoldCo Drag)			*(0.03)*	*(0.02)*	*(0.02)*	*(0.02)*	
DP&L Gen EPS (Non-Bypassable + GenCo)			*0.08*	*0.13*	*0.10*	*0.02*	
Consolidated Tax Rate Assumptions			*30%*	*31%*	*32%*	*33%*	*33%*

Source: Company Filings, FactSet, and UBS Estimates

Will DPL file for an ESP in Ohio too?

Over the course of this quarter, both FE and AEP have filed for a new Electric Security Plan (ESP) before the Ohio Commission (PUCO) for a PPA rider that essentially enter into an above market PPA for specific assets in the state.

The plants included in AEP's petition include units that are co-owned with DPL (AES is parent) and DUK (soon to be DYN), suggesting that if successful, the other owners are likely to seek similar treatment. Specifically, we see AES (through DPL) as highly likely to ask as part of its next ESP filing (current term expires in Dec '16), suggesting its next filing is a 2015 event.

Figure 218: AES' attributable MW ownership across plants for which AEP has filed an ESP for

Ownership (%)	AEP	DUK/DYN	DPL(AES)
Cardinal	100.0%		
Conesville	71.2%	20.4%	8.4%
Stuart	26.0%	39.0%	35.0%
Zimmer	25.4%	46.5%	28.1%

MW Ownership	AEP	DUK/DYN	DPL(AES)
Cardinal	592		
Conesville	1,149	312	129
Stuart	600	900	808
Zimmer	330	605	365

Source: SNL, Company filings

If all of DPL (AES)'s co-owned assets were contracted, this would represent 1.3GWs. Assuming the same contract rate, this would be ~$100 Mn, or **$0.09 EPS uplift.**

What's happening in California?

With contracts expiring, seeking the next step in contracts & repowering

2018 contract expiration is the next cliff for AES to address

Can it sell down a repowering to monetize the portfolio?

We think the 'extended draught' thesis in California will for the time being somewhat delay our negative expectations for energy prices due to growing renewables penetration. Fundamentally, we think there are substantial pressures on capacity and energy prices in California, as the renewable build continues unabated (~2GW/yr growth) coupled with nascent storage efforts and inter-regional imports via expanded an expanded Energy Imbalance Market (EIM).

Nonetheless, NP15 spark spreads have remained flat or even rising through the 2015-17 period, largely on account of the deepening drought.

Although AES in California is mostly contracted, it does nonetheless have some exposure. In the table below we summarize AES' Californian IPP portfolio.

Figure 219: AES IPP Owned Assets in California

Power Plant	Fuel Type	MW	Heat Rate	MWh
Alamitos	Steam Turbine	1,997	10,830	1,464,747
Huntington Beach	Steam Turbine	452	10,763	1,167,621
Redondo Beach	Steam Turbine	1,334	12,327	547,638
	Total AES	3,783		3,180,006

Source: SNL, UBS estimates

We're lowering our California segment valuation

We see less value here as contracts mature – mgmt appears to be pro-actively pursuing opportunities

We're reducing our multiple on the California portfolio in our SOP to 6x EBITDA to reflect the pending expiration of this PPA in 2018 (4-years left), as well as the potential repowering opportunity across the portfolio. Notably, all of these assets face once-through cooling, with all three slated to shut in 2020 (we don't expect delays).

How we value it now?

2015-2017 EBITDA = ~$120 Mn/yr

2018-2020 EBITDA = ~$50 Mn/yr

We estimate the NPV of FCF is ~$380 Mn through the decade, and add to that ~$200 Mn in repowering value for Huntington Beach (SCE RFP is pending), as well as ~$100 Mn value to the balance (Redondo / Alamitos), which are not as clear repowering candidates.

This totals ~$700 Mn in enterprise value, implying a 6x EV/EBITDA. While our consolidated SOP remains at $15/sh, the latest reduces our target by ~$0.40/sh from our prior 9x multiple applied (generic IPP assumption we use across the sector)

What's the EPS impact? We think the 2018 roll-off of the Mercuria tolls with the plants is a drag of ~$0.03-0.06 in EPS depending on the pricing environment for capacity once RA contracts are extended (assuming all of the capacity can be through its remaining life)

Huntington Beach received initial CEC nod over 3Q

In early September, the California Energy Commission's (CEC) presiding members approved the AES Southland's Huntington Beach Energy Project (HBEP; essentially a plant repowering project) in an initial ruling. This is not the final license, but a step in the right direction.

Under the plan, Huntington Beach will be repowered to be a 939 MW (nominal) combined cycle power plant, using the Mitsubishi M501DA gas turbine. **The question remains whether AES could yet be awarded this project in the upcoming SCE thermal RFP.**

We see the Southland portfolio as a potential for asset sale candidate

We see the plant as an ideal YieldCo sale candidate; with management keen to divest any asset that could garner a premium multiple, we see AES as a likely seller of any successful development efforts in California.

Mexico – A Future Growth Opportunity

Management has reiterated that their assets in Mexico as a good brand and are looking at growth opportunities in that market. However, we don't have any details yet in terms of what the growth strategy is. We look for more updates on plans in Mexico from management in coming months.

Turkey: Selling down the previous growth focus

We see the 14 P/E as a great example of accretive asset sale

AES announced early this week that it is exiting operations in Turkey, by selling its 49.62% equity interest in AES Entek to its JV partners for **$125mn**. Management does not expect any significant tax impact from the sale post debt pay down. With $9mn in equity earnings, the sale implies a 14x P/E exit multiple. We expect management to give more clarity on use if these proceeds in the 3Q call.

Notably, this a move away from a 'growth country' previously articulated by management in prior Analyst Days (the growth opportunity is likely reflected in part in the better P/E valuation methodology).

India

Coal supply issues persist

In late September, the Supreme Court of India passed a verdict ruling all coal block allocations to private corporations (made since 1993) illegal, and also imposed a penalty on companies that had won those initial allocations. The ruling directly impacts domestic coal availability for power generation and profitability of power plants as they would need to purchase coal at higher market/imported prices rather than from 'captive' coal mines (i.e., mines allocated directly to the private power project owner for self-production and consumption).

AES' footprint in India revolves around its 49% stake in the 420MW coal-fired Odisha Power Generation Corp project, which is undergoing an expansion of 2640MW for which it had been allocated two captive coal blocks (with 531mn tonnes of aggregate resources) by the Government – both these captive coal mines will now be impacted by the Supreme Court ruling.

AES has said that the state government in Orissa as well as lenders in India continue to support their project, and that although there will be definite degradation of an already tight coal supply issue, the broader infrastructure policy-focus of the Narendra Modi led BJP government at the Center should eventually loosen supply bottlenecks. We continue to think that a short term solution to tight fuel supply situation will remain elusive. About half of AES' output is sold to the Power Grid, and for those sales fuel cost is a pass-through. The remaining half is sold in the open market where fuel procured at a higher cost will not be a pass-through.

Bulgaria

PPA renegotiation ongoing

Contracting issues appear pervasive in the country, following AES' completion of its coal plant in 2012. With the plant contributing $0.11-0.12 we see any change in the PPA as potentially negative in the near term, but likely retaining the overall value of the deal. Given the plant's 15-year offtake agreement (paid in Euros) with the national utility, NEK (*contract is not with the regulator*), we see a variety of win-win outcomes to ease pressure on consumer prices. Any update on the contract remains a 2015 development given timing under the new government. We also emphasize given the substantial participation of the European Bank for Reconstruction and Development (EBRD) among other regional lenders, there is likely meaningful sovereign influence in limiting project offtake abandonment. The timing of the latest flare up is relatively surprising, seeing the winter heating season as typically the pinch-point on consumers.

In Bulgaria AES has settled $45Mn of overdue receivables and confirmed that it will "defend the PPA" in response to any challenge at its 690MW Maritza coal plant.

~$0.10/sh of EPS from Bulgaria

Figure 1: Bulgaria Mini-Model – worth quite a bit to consolidated AES' EPS

Macro Economic Data:	2012A	2013A	2014E	2015E	2016E
Avg. F/X Rate (USD/EUR)	1.26	1.23	1.23	1.23	1.23
Real GDP Growth	3.50	3.70	3.80	3.90	4.00
Inflation Rate	3.73	2.91	3.00	3.00	3.00
US Inflation rate	1.82	2.27	1.24	1.53	1.54
Electricity Consumption Growth Rate					
EBITDA EUR	221	221	221	221	221
EBITDA $USD	279	271	271	271	271
Depreciation	70	70	70	70	70
EBIT (Equiv of Gross Margin?)	151	151	151	151	151
Interest	48	48	48	48	48
Debt Outstanding	804	827	827	827	827
EBT	103	103	103	103	103
Net Income in local currency	72	72	72	72	72
Net Income ($USD)	91	59	59	59	59
Net Income Contribution (Guidance)	$0.11-0.12				

Source: Company Filings and UBS Estimates

AES Bulgaria is a material part of our valuation (~10%) and we have left our estimates unchanged as we believe it is premature to evaluate the impact. Reducing our 2015 EV / EBITDA multiple 1x-turn to 6x from 7x would reduce our valuation by ~$0.40/sh.

Puerto Rico

PREPA risk remains, but management certain contract will be honored

Puerto Rico nominated a Chief Restructuring Officer in early September for restructuring Puerto Rico Electric Power Authority (PREPA), after its debt was downgraded to 'extremely speculative' by credit rating agencies earlier this year. <u>We estimate this asset generates among the most EPS for AES in the North American generation segment, at ~$0.05.</u>

Unlikely for PREPA to push back on AES contract, but still a risk as the territory looks to halve bills

Following the PREPA downgrades, AES Puerto Rico, L.P. had also been downgraded by Moody's to B3 from Ba2 on negative watch. Moody's cites AES Puerto Rico's higher position in a reorganization (operating expense) and the "strategic importance of the low cost power supply" as elaborated on below.

We suspect investors will be on high alert around this contract

AES management remains confident in its contract with PREPA which saves PREPA ~$250Mn per year ($0.095/kwh from AES versus $0.20/kwh for PREPA generation). AES is operating under a 25-year PPA with PREPA which is set to expire in 2027.

Figure 220: PREPA Credit Ratings

Agency	Rating	Watch	Date	Previous Rating
Moodys	Caa2	NEG	7/1/2014	Ba3
S&P	CCC	NEG	7/31/2014	B-
Fitch	CCC	NEG	6/26/2014	BB

Source: Bloomberg

AES International Commodity Update

Underlying International Commodity Performance

Both International and domestic coal prices have continued their declines. This is a broad tailwind for AES given modest merchant exposure on coal inputs across its portfolio, particularly to international prices.

Figure 221: Newcastle Coal ($/ton), International Coal Proxy

Source: FactSet

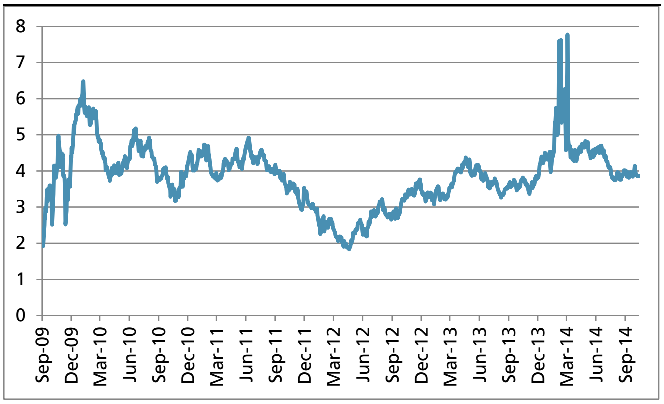
Figure 222: NYMEX CAPP Coal ($/ton), Domestic Coal Proxy

Source: FactSet

Comparing the Forward Gas Months: US vs. Europe

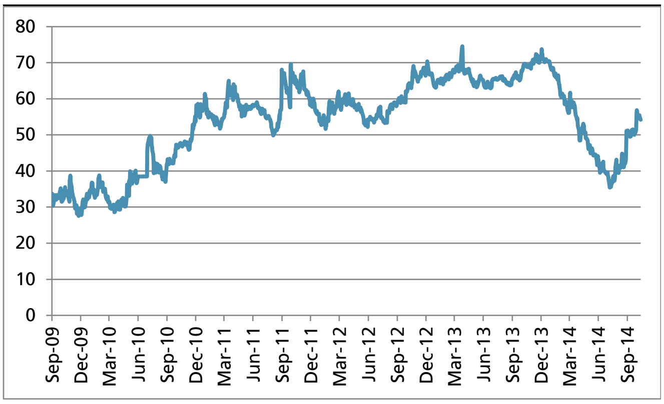
Henry Hub natural gas rose from August '13 lows of ~$3.23/MMBtu to a high of $6.15 on February 19th. They have been declining steadily since then and traded around ~$3.92 on October 13th. YTD, Henry Hub natural gas prices fell by 6.6%. Meanwhile, European gas prices have experienced sharp decline (-23.6%, YTD) 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. Our latest NYMEX natural gas price forecasts for 2014-16 are $4.45/$3.75/$4.25 $/MMBtu lowered from our earlier forecasts of $4.75/$4.50/$5.00 due to strong US supply growth.

Figure 223: US Natural Gas (Henry Hub), $/MMBtu



Source: FactSet; 4Q11 Guidance (2012) = $3.2/MMBtu

Figure 224: European Natural Gas (NBP), pence/therm

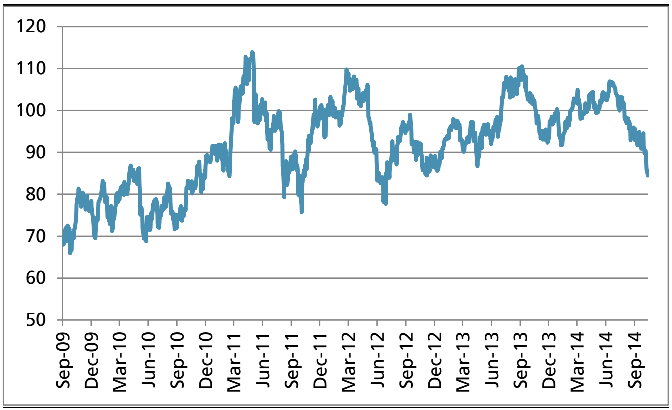


Source: Bloomberg; 4Q11 Guidance (2012) = £0.57/therm

Oil Prices: US vs. Europe

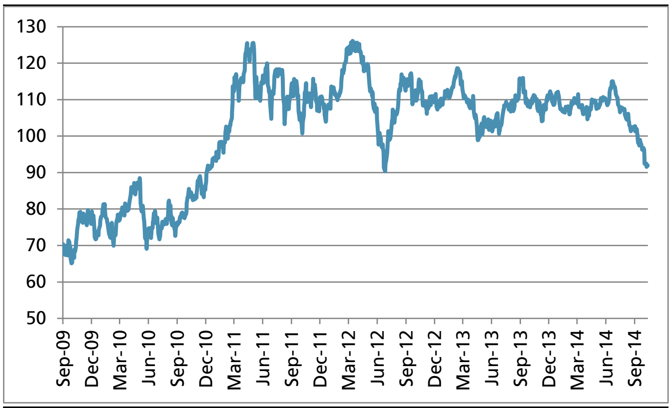
Meanwhile, both domestic and international oil fell by ~5.5% in 3Q14 on QoQ basis. YTD Brent prices have fallen 19.3% to $89.41/Bbl, while YTD Crude WTI prices have decreased by 12.9% to $85.74/Bbl. We note UBS' revised 2014 Brent/WTI crude oil forecasts are $105.30/Bbl and $98.50/Bbl.

Figure 225: Crude Oil (WTI), $/Bbl



Source: FactSet

Figure 226: Crude Oil (IPE Brent), $/Bbl



Source: FactSet

Brazil

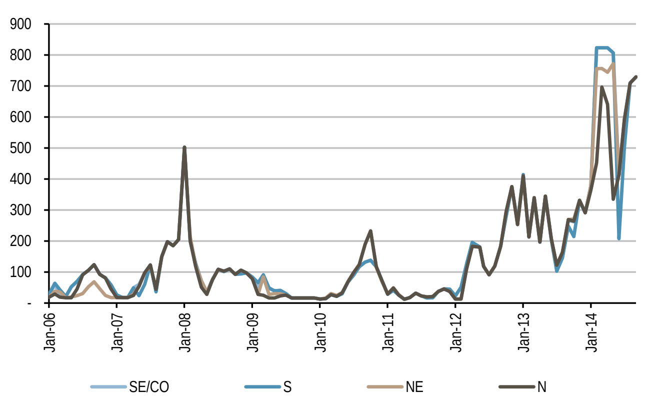
Improving outlook for long term power prices, but near term risks continue for Tiete

UBS LatAm utilities analyst, Lilyanna Yang, highlights that market prices for one-year contracts point to R$350-400/MWh for delivery in 2015e, R$220-250/MWh for 2016e and R$140-150/MWh for 2017-18e onwards (although with low volume liquidity). AES Tiete could be one of the primary beneficiaries from a higher price curve.

Nearer term, however, hydrology/shortage risk remains relevant, despite weak demand growth, as illustrated by 14-18% hydro generation shortfall in July-Aug and also by high spot prices (~R$682/MWh in late September/early October). This may pose near term profitability risk, as the shortfall will have to be met by purchases in the spot market. AES Tiete has likely been selling energy contracts, but without much volume. Every R$10/MWh in higher power prices over the long-run can impact valuations of Gencos positively at ~ R$1/sh for AES Tiete stocks. Management has said that it is too early to forecast hydrology for 2015, since the rainy season in Brazil is yet to arrive – it starts in October/November and continues till April.

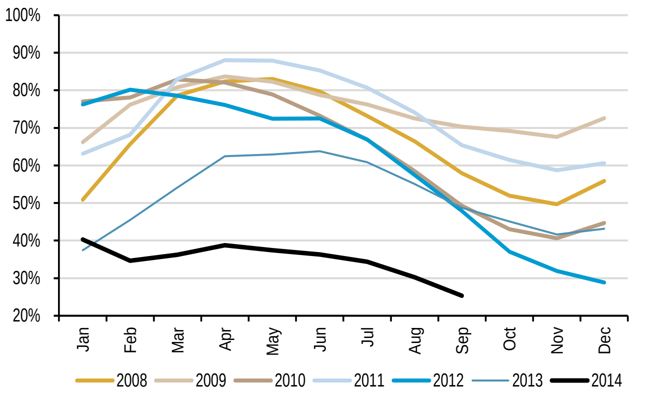
Overall we think unfavorable hydro will leave AES at the low end of 2014 adjusted EPS range, but at the same time highlight that we see upside to recontracting long term EPS for 2016+. We look for details on this

Figure 227: Brazilian Spot Power Prices ($Rs/MWh)



Source: ONS

Figure 228: Brazilian Hydrology – Reservoir Levels for Southeast



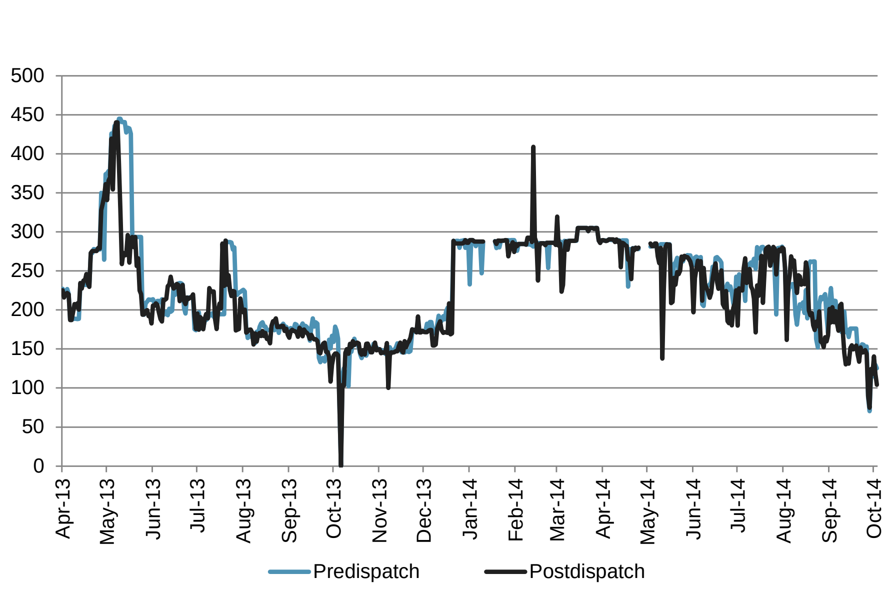
Source: ONS

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.

Hydrology in Panama has also improved significantly following a severe drought in 2013 similar to others in South America. We see the normalization of prices in this market, coupled with additional investment in oil barges as likely insulating the company from further headwinds in this market.

Figure 229: Panama Spot Prices- Pre/Post-Dispatch ($/MWh) – Slightly off the recent highs



Source: Company Reports

Politics in Brazil remain key: We think AES could remain under pressure going into the elections given the uncertainty. The market friendlier candidate Aecio Neves (PSDB) will go to the second round of presidential elections against incumbent Dilma Rousseff (PT). Rousseff got 42% of the votes vs. 34% for Neves and 21% for Silva.

Eletropaulo gets a court injunction against order to pay ~$260 million consumer rebate

In late September, AES' Brazilian subsidiary Eletropaulo Metropolitana SA got a court injunction against the regulator ANEEL's order to pay a R$626mn (~$260 million) consumer rebate. The initial ANEEL ruling was based on allegations that Eletropaulo inflated its asset base by improperly including some power cables as company assets. The ruling comes after ANEEL had already earlier in the year penalized Eletropaulo for ~50% of that fine by allowing it an 18.66% annual tariff adjustment, which was 3.3% lower than what it was due.

Separately, Eletropaulo management believes the tariff reset parameters for the power distribution rate review process will improve. UBS' LatAm utilities analyst agrees, but highlights that improvements come from a very low base and might not be sufficient to support substantial margin expansion in the near-term.

F/X Rate Fluctuations

We include charts of currency affecting AES. The next table showcases the YoY percentage changes in the foreign exchange rates. The broader dollar appreciation is a headwind for AES shares, partially offset by largely dollarized businesses abroad.

Figure 230: YoY Percentage changes in Currencies

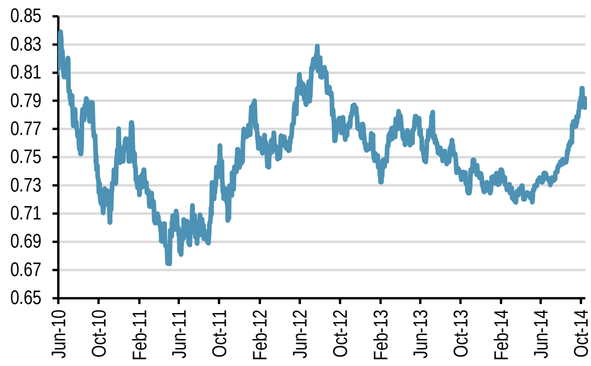
YoY % changes					
USD/ EURO	USD/Brazilian Real	USD/Chilean Peso	USD/Argentinean Peso	USD/ Mexican Peso	USD/ Peruvian Sol
6.5%	9.9%	18.5%	45.4%	5.0%	3.5%

Source: FactSet

Figure 231: F/X Rate for USD / Brazilian Real

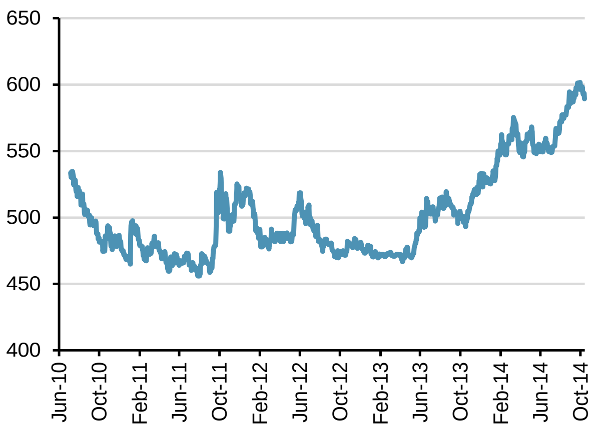
Source: FactSet

Figure 232: F/X Rate for USD / Euro



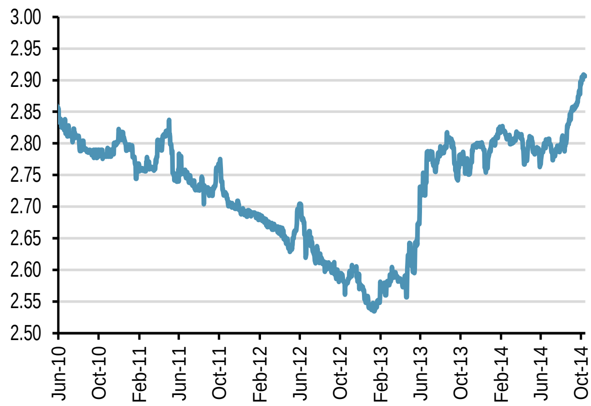
Source: FactSet

Figure 233: US Dollar per Chilean Peso



Source: FactSet

Figure 234: US Dollar per Peruvian New Sol

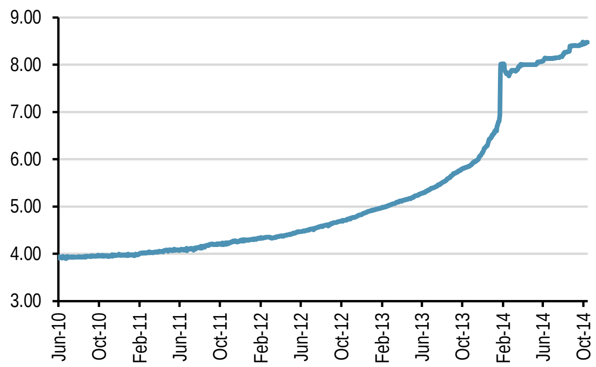


Source: FactSet

Figure 235: US Dollar per Mexican Peso

Source: FactSet

Figure 236: F/X Rate for USD / Argentine Peso



Source: FactSet

We believe the two largest currency exposures for AES are the Brazilian Real through its Tiete, Eletropaulo, and Sul segments and the Euro through its European renewables and Eastern European generation footprint. AES on its 2Q14 call stated that its 2014-2018 Outlook is based on foreign currency exchange rates and commodity curves as of 6/30/2014. On the 2Q14 call, it estimated a 10% appreciation in the USD relative to the Brazilian Real and Euro translates to negative EPS impacts of $0.005 and less than $0.005 respectively.

We also include the USD / Argentine Peso exchange rate; on a full year basis every 10% appreciation in the USD is a negative $0.005 EPS impact. The USD has appreciated in the last few months, continuing the nearly unbroken upward trend-line. It remains challenging to calculate a precise assumption for EPS headwind, but we estimate it to be a few pennies in negative F/X to AES YoY. As a reminder, the company is limited from taking any distributions from the country at present, so the latest spike does not impact parent FCF.

Energy Futures Holding (Not Rated)

Asset sales could potentially create significant tax liabilities for EFH

In an early October court filing EFH has warned that unless bankruptcy reorganization is structured appropriately, any sale of subsidiary businesses or assets could create a significant federal income tax liability for EFH. In its filing, EFH used hypothetical examples showing a $3.7bn tax liability on EFH of TCEH was sold for $18bn; and tax liability of $3.4bn incase EFIH (which has a 80% interest in Oncor) is sold for around $8bn. The filing says that under existing structures the tax liability will be on EFH and not on TCEH and EFIH. The filing also states that EFH does not expect it will be able to pay a significant part of such a tax liability, and may thus lead to further litigation and even potential liquidation rather than reorganization.

A bidding war for Oncor: prospective timelines

Nonetheless, interest for Oncor has seen substantial interest (22 buyers, including AEP, CNP, and NEE according to media reports, have been invited back to participate in the final round), and has also become somewhat politicized over 3Q. Senator Fraser (Chairman of the Senate Committee on Natural Resources) has commented that he prefers a strategic (rather than financial buyer) of the assets. Meanwhile, other statements in Austin suggest a preference for a 'local' owner – this would seemingly imply Texas, but this could also be interpreted to suggest domestic ownership, following recent media speculation European Utility Iberdrola was weighing a bid for Louisiana-based Cleco (latest media reports suggest Iberdrola has dropped out of the process).

In September, EFH filed for approval of auction rules for potential bidders. Under the rules filed for approval, EFH will be accepting sealed bids until October 23, and then refine details with a narrower set of bidders until November 21. The highest bid in this stage will then serve as the minimum required value to be submitted during the open bidding process, which will last for a couple of months. The winning bidder will be then obligated to close the deal by 31 December 2015.

Updating Competitive Projections from Management

Below we include an updated 'mark-to-market' of management's previously disclosed projections for EHF's IPP business, Luminant.

Figure 237: Updated Adjusted EBITDA and FCF using Mgmt Projections on Current ERCOT Forwards

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 ($/t), UBSe	27	28	29	30	31	32
Fuel Cost (Only Coal/Nuclear Fuel Excl from Adj. EBITDA)	1,020	1,011	1,050	1,168	1,179	1,191
Baseload-Only Gross Margin (UBSe), as of Feb 1st	**1,500**	**1,554**	**1,643**	**1,796**	**2,107**	**2,098**
Asset Management, *using this as Plug to Mgmt*	**359**	**1,398**	**299**	**107**	**74**	**190**
Open Luminant EBITDA (UBSe), as of Feb 1st	625	679	768	921	1,232	1,223
Add : Hedges (As disclosed by Mgmt) - 4/29/14 8K	1,018	(587)	-	-	-	-
Hedged Luminant (Generation) EBITDA (UBSe), as of Feb 1st	2,002	1,490	1,067	1,028	1,232	1,223
Add : TXU Energy, Retail Business EBITDA (from above)	719	619	589	559	544	529
Hedged TCEH EBITDA (UBSe), as of Feb 1st	2,721	2,109	1,656	1,587	1,776	1,752
Implied All-in Fuel, O&M, SG&A Costs ($/MWh)	27	28	28	28	29	29
Guidance	30-32					
ERCOT-North (ATC) - MtM		39.80	36.87	37.66	39.26	39.04
Reflecting the Latest Commodity Shifts						
ERCOT-North (ATC) - MtM Improvement/(Declines), $/MWh		3.54	(1.58)	(2.70)	(5.93)	(6.63)
Volumes		68	68	72	72	72
Change in Hedge Value since Feb 1st		241	(107)	(195)	(427)	(477)
Hedged TCEH EBITDA (Mgmt Projections), using latest MtM		**2,350**	**1,549**	**1,392**	**1,423**	**1,465**
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**	**944**	**897**	**968**	**737**
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**	**859**	**821**	**891**	**711**

Source: Mgmt Projections, Platts, and UBS calculations

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 or ability to repurchase sufficient quantities of mandatory Shares may yet 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.

Exelon Corp. Investment Case

While having substantially improved its outlook following its dividend cut with 4Q, we remain cautious as to the next direction for power prices following the recent sell-off. Meanwhile its regulated utilities will continue to see an improving profile, picking up the majority of the coverage, but not all, for its new reduced dividend. The pending POM deal should benefit shares if able to gain the necessary approvals.

NRG Energy Inc. Investment Case

Shares remain particularly levered to natural gas prices through its large coal portfolio in Texas. We look for market reforms in ERCOT to eventually improve heat rates independent of natural gas prices but do not view any material uplift in the near-term. NRG has diversified away from Texas in the past year (Gulf Coast Adj. EBITDA contribution down from 49% to 21%). We think the name may be appealing to those seeking substantial leverage to gas and power prices and we look for clarity on rooftop solar distributed generation (DG) and capital redeployment in the upcoming months.

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

Required Disclosures

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UBS Investment Research: Global Equity Rating Definitions

12-Month Rating	Definition	Coverage[1]	IB Services[2]
Buy	FSR is > 6% above the MRA.	47%	34%
Neutral	FSR is between -6% and 6% of the MRA.	42%	28%
Sell	FSR is > 6% below the MRA.	11%	21%
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 September 2014.
1:Percentage of companies under coverage globally within the 12-month rating category. 2:Percentage of companies within the 12-month rating category for which investment banking (IB) services were provided within the past 12 months.
3:Percentage of companies under coverage globally within the Short-Term rating category. 4:Percentage of companies within the Short-Term rating category for which investment banking (IB) services were provided within the past 12 months.

KEY DEFINITIONS: Forecast Stock Return (FSR) is defined as expected percentage price appreciation plus gross dividend yield over the next 12 months. **Market Return Assumption (MRA)** is defined as the one-year local market interest rate plus 5% (a proxy for, and not a forecast of, the equity risk premium). **Under Review (UR)** Stocks may be flagged as UR by the analyst, indicating that the stock's price target and/or rating are subject to possible change in the near term, usually in response to an event that may affect the investment case or valuation. **Short-Term Ratings** reflect the expected near-term (up to three months) performance of the stock and do not reflect any change in the fundamental view or investment case. **Equity Price Targets** have an investment horizon of 12 months.

EXCEPTIONS AND SPECIAL CASES: UK and European Investment Fund ratings and definitions are: Buy: Positive on factors such as structure, management, performance record, discount; **Neutral:** Neutral on factors such as structure, management, performance record, discount; **Sell:** Negative on factors such as structure, management, performance record, discount. **Core Banding Exceptions (CBE):** Exceptions to the standard +/-6% bands may be granted by the Investment Review Committee (IRC). Factors considered by the IRC include the stock's volatility and the credit spread of the respective company's debt. As a result, stocks deemed to be very high or low risk may be subject to higher or lower bands as they relate to the rating. When such exceptions apply, they will be identified in the Company Disclosures table in the relevant research piece.

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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[2, 4, 6a, 16]	AES.N	Neutral	N/A	US$13.21	14 Oct 2014
Ameren Corp.[6a, 16]	AEE.N	Neutral	N/A	US$40.72	14 Oct 2014
American Electric Power, Inc.[4, 6b, 7, 16]	AEP.N	Neutral	N/A	US$54.72	14 Oct 2014
Avista Corp[1, 2, 4, 5, 6a, 6c, 7, 16]	AVA.N	Neutral	N/A	US$34.03	14 Oct 2014
Calpine Corporation[2, 4, 6a, 16]	CPN.N	Neutral	N/A	US$20.67	14 Oct 2014
CMS Energy Corporation[6a, 16]	CMS.N	Not Rated	N/A	US$31.07	14 Oct 2014
Consolidated Edison[6a, 16]	ED.N	Neutral	N/A	US$61.57	14 Oct 2014
Dominion Resources[2, 4, 5, 6a, 6b, 6c, 7, 16]	D.N	Buy	N/A	US$68.18	14 Oct 2014
DTE Energy Co.[2, 4, 6a, 16]	DTE.N	Neutral	N/A	US$79.51	14 Oct 2014
Duke Energy[2, 4, 6a, 16]	DUK.N	Buy	N/A	US$78.87	14 Oct 2014
Dynegy, Inc.[2, 4, 5, 16]	DYN.N	Buy	N/A	US$27.46	14 Oct 2014
Edison International[6a, 16]	EIX.N	Buy	N/A	US$59.80	14 Oct 2014
Empire District Electric Company[16]	EDE.N	Neutral	N/A	US$25.87	14 Oct 2014
Entergy Corp.[16]	ETR.N	Neutral	N/A	US$81.04	14 Oct 2014
Exelon Corp.[4, 6a, 6c, 7, 16]	EXC.N	Neutral	N/A	US$34.64	14 Oct 2014
FirstEnergy Corp.[16]	FE.N	Sell	N/A	US$35.56	14 Oct 2014
ITC Holdings Corp[13, 16]	ITC.N	Buy	N/A	US$34.97	14 Oct 2014
NextEra Energy[2, 4, 6a, 16]	NEE.N	Buy	N/A	US$93.34	14 Oct 2014
NextEra Energy Partners LP[2, 4, 5, 6a, 16]	NEP.N	Neutral	N/A	US$29.90	14 Oct 2014
Northeast Utilities[6a, 13, 16]	NU.N	Buy	N/A	US$47.56	14 Oct 2014
NRG Energy Inc.[16]	NRG.N	Buy	N/A	US$28.12	14 Oct 2014
NRG Yield[16]	NYLD.N	Neutral	N/A	US$42.08	14 Oct 2014
PG&E Corporation[6a, 16]	PCG.N	Neutral	N/A	US$45.88	14 Oct 2014
Pinnacle West Capital Co.[2, 4, 6a, 16]	PNW.N	Buy	N/A	US$57.92	14 Oct 2014
PPL Corporation[2, 3, 4, 6a, 6c, 7, 16]	PPL.N	Neutral	N/A	US$33.59	14 Oct 2014
Public Service Enterprise Group[6b, 7, 16]	PEG.N	Neutral	N/A	US$38.69	14 Oct 2014
SCANA Corp.[4, 5, 6a, 16]	SCG.N	Neutral	N/A	US$51.22	14 Oct 2014
Sempra Energy[2, 4, 6a, 16, 18]	SRE.N	Buy	N/A	US$102.00	14 Oct 2014
Southern Company[2, 4, 5, 6a, 16]	SO.N	Sell	N/A	US$46.90	14 Oct 2014
TECO Energy Inc.[16]	TE.N	Neutral	N/A	US$18.53	14 Oct 2014
Westar Energy, Inc.[4, 6a, 16]	WR.N	Buy	N/A	US$36.19	14 Oct 2014
Wisconsin Energy Corp.[16]	WEC.N	Neutral	N/A	US$47.27	14 Oct 2014
Xcel Energy Inc.[6a, 16]	XEL.N	Neutral	N/A	US$32.70	14 Oct 2014

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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