

US Electric Utilities & IPPs

2Q16 Playbook: A Guide to Catching ‘Em All

Don't Get Lost: Finding the best ways to play the sector into 2Q earnings

We summarize 2Q results as not just constructive across the board, given our perception of continued utility sector upside, but perceive clear opportunities for discrete outperformance across a number of equities. Much of the positive sentiment is driven by the potential for clarified strategic vision (FE) and re-rating potential from these actions (DUK, AEP). Additionally, potential for state-sponsored support for struggling merchant nuclear and coal units appears to be underway, with a variety of equities benefitting including EXC and PEG. Overall, results appear to be quite active for mid-summer, with clean potential for more volatility than usual. We are indeed cautious on a number of equities but largely perceive issues arising from larger projects – either under construction (SO & SCG) or related to permitting risks (ES). For more please see our reports on the [Integrated Utilities](#), [Regulated Utilities](#), and [IPPs](#) for breakdowns on respective themes and company-specific views. Below, we reflect our summary views on each stock as well as latest top picks and 2Q calls out of these.

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US Power & Utilities "2Q16 Integrated Preview: Nuclear's Time to Shine?" 21 July 2016

US Regulated Electric Utilities "2Q16 Utility Preview: Coming to Terms with Rates" 20 July 2016

US Power "2Q16 Power Preview: Sparking Up" 19 July 2016

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Contents

The PM Summary of 2Q Results.....	6
Latest Thoughts on Integrated Utility Space	13
Latest Thoughts on Regulated Utility Space.....	16
Interest Rate Views and Macro Views.....	18
Appendix:	26
Latest Thoughts on Power Markets.....	27
PJM: Investor Denial on Limited Recovery.....	28
ERCOT: Don't Everyone Move At Once	31
Renewables threaten the recovery	33
MISO: Riding the Roller Coaster.....	37
New England: Running on Empty?.....	40
New York: Limiting the Carbon.....	45
California: Arguing the Near-Term Case	49
Where's the UBS Gas Forecast?.....	53
Power Market Preferences	59
Ameren Corp.	60
American Electric Power	64
Avista Corp.	68
Calpine Corporation.....	72
CMS Energy Corporation	80
Consolidated Edison	84
Dominion Resources	89
DTE Energy Co.	96
Duke Energy	100
Dynegy Inc.	104
Edison International.....	110
Empire District Electric Company	113
Entergy Corp.....	115
Eversource Energy.....	125
Exelon Corp.	129
FirstEnergy Corp.....	135
ITC Holdings Corp.....	140
NextEra Energy.....	142
NRG Energy Inc.....	149
PG&E Corporation	158
Pinnacle West	163

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Portland General Electric	167
PPL Corporation.....	172
Public Service Enterprise Group	177
SCANA Corp.....	182
Sempra Energy	186
Southern Company	195
Talen Energy Corp.....	200
WEC Energy Group Inc.....	202
Westar Energy	205
Xcel Energy	207
AES Corp	211
EFH (Unrated)	228

Summarizing the Universe

Figure 1: Utilities Comp Table

	Ticker	Rating	Market Cap. (\$ in millions)	Price 7/21/2016	Price Target	Dividend Yield	Short Interest	Days to Cover	P/E Multiple			
									2016E	2017E	2018E	2019E
COMPETITIVE INTEGRATED												
American Electric Power, Inc.	AEP	Buy	34,063	69.33	77.00	3.23%	1.1%	2.3	18.7	18.0	16.9	16.9
Avangrid Inc	AGR	Not Rated	13,770	44.55	NA	3.88%	1.9%	2.0	21.1	19.2	17.6	16.8
Dominion Resources	D	Neutral	47,757	77.50	77.00	3.61%	3.1%	5.0	20.5	20.5	18.3	17.2
Entergy Corp.	ETR	Sell	14,326	80.15	75.00	4.24%	1.7%	2.4	16.5	14.4	15.6	14.4
Exelon Corp.	EXC	Neutral	32,387	36.50	38.00	3.48%	1.9%	2.7	14.2	13.6	12.6	13.1
FirstEnergy Corp.	FE	Neutral	15,275	35.96	35.00	4.00%	2.4%	2.6	14.4	16.3	15.3	16.1
NextEra Energy	NEE	Buy	59,130	128.14	140.00	2.72%	2.2%	4.2	20.3	18.9	18.0	17.9
Public Service Enterprise Group	PEG	Buy	23,242	45.94	50.00	3.57%	2.1%	3.0	16.0	15.7	15.5	16.3
Sempra Energy	SRE	Buy	28,173	112.92	123.00	2.67%	1.6%	3.0	23.6	23.0	18.3	15.8
Average						3.49%	2.0%	3.0	18.4	17.7	16.5	16.1
REGULATED INTEGRATED UTILITIES												
Large Cap	Ticker	Rating	Market Cap	Price	PT	Yield	Short	Days	2016E	2017E	2018E	2019E
Ameren Corp.	AEE	Neutral	12,658	52.17	53.00	3.26%	2.2%	3.3	21.0	18.8	17.7	16.7
Alliant Energy Corp.	LNT	Not Rated	9,023	39.73	NA	2.96%	2.9%	1.1	21.0	19.7	18.7	17.9
CenterPoint Energy Inc	CNP	Not Rated	10,430	24.22	NA	4.25%	3.2%	3.1	21.1	20.0	18.7	18.1
CMS Energy Corporation	CMS	Neutral	12,623	45.09	45.00	2.75%	3.5%	3.7	22.3	20.9	19.5	18.3
Consolidated Edison	ED	Sell	24,167	79.80	72.00	3.36%	4.0%	4.9	19.4	19.6	19.0	18.0
DTE Energy Co.	DTE	Buy	17,637	98.29	108.00	3.13%	1.4%	2.3	19.9	18.4	16.9	15.4
Duke Energy	DUK	Buy	58,770	85.31	93.00	4.01%	2.9%	5.6	18.4	17.8	17.0	16.4
Edison International	EIX	Buy	25,013	76.77	79.00	2.50%	1.5%	2.7	19.8	18.4	17.6	16.3
Eversource Energy	ES	Neutral	18,403	58.02	61.00	3.07%	1.4%	2.4	19.5	18.8	17.8	16.7
PG&E Corporation	PCG	Neutral	31,831	64.17	67.00	3.05%	0.9%	1.3	17.4	17.9	17.1	16.2
Pinnacle West Capital Co.	PNW	Neutral	8,852	79.65	80.00	3.14%	3.2%	4.5	19.9	19.1	17.6	17.2
PPL Corporation	PPL	Buy	25,128	37.12	41.00	4.09%	1.1%	1.0	16.0	15.4	14.9	14.5
SCANA Corp.	SCG	Neutral	10,596	74.14	72.00	3.10%	4.1%	4.9	18.8	17.7	16.9	16.3
Southern Company	SO	Sell	50,583	53.90	51.00	4.16%	2.2%	3.1	19.0	18.9	18.1	17.5
WEC Energy Group Inc.	WEC	Neutral	20,426	64.71	63.00	2.63%	3.2%	4.0	22.0	20.8	19.4	18.4
Xcel Energy Inc.	XEL	Sell	22,271	43.85	42.00	3.10%	2.3%	3.2	19.9	19.1	18.3	17.2
Average						3.29%	2.5%	3.2	19.7	18.8	17.8	16.9
Small and Mid-Caps	Ticker	Rating	Market Cap	Price	PT	Yield	Short	Days	2016E	2017E	2018E	2019E
ALLETE	ALE	Not Rated	3,131	63.56	NA	3.27%	2.1%	3.4	19.9	18.0	17.7	16.5
Avista Corp	AVA	Sell	2,761	43.68	39.00	3.14%	3.1%	4.6	21.2	20.5	19.6	18.7
Black Hills Corp	BKH	Not Rated	3,194	61.92	NA	2.71%	10.0%	13.1	20.5	17.5	16.0	na
El Paso Electric Co.	EE	Not Rated	1,913	47.26	NA	2.62%	1.8%	2.2	18.9	18.0	17.2	16.2
Great Plains Energy	GXP	Not Rated	4,660	30.12	NA	3.49%	3.2%	2.2	17.5	16.6	15.7	14.9
Hawaiian Electric Industries	HE	Not Rated	3,315	30.73	NA	4.04%	1.5%	2.4	18.1	17.2	16.1	15.6
Idacorp, Inc.	IDA	Not Rated	4,056	80.46	NA	2.54%	2.0%	2.4	20.7	20.0	19.6	na
MGE Energy	MGEE	Not Rated	1,950	56.24	NA	2.10%	2.4%	5.2	24.5	23.0	22.1	21.2
NorthWestern Corp	NWE	Not Rated	2,965	61.38	NA	3.26%	2.5%	3.5	18.7	17.9	16.7	15.9
Portland General Electric Company	POR	Buy	3,952	44.45	49.00	2.88%	2.7%	4.2	20.3	18.5	17.1	16.1
PNM Resources Inc.	PNM	Not Rated	2,708	34.00	NA	2.59%	3.6%	4.2	21.2	18.1	16.4	15.8
Spire Inc	SR	Not Rated	3,137	68.74	NA	2.85%	4.4%	7.0	20.3	19.5	19.2	17.4
OGE Energy Corp	OGE	Not Rated	6,391	32.01	NA	3.44%	2.5%	3.7	18.1	17.0	15.7	15.1
Otter Tail Corp	OTTR	Not Rated	1,314	34.47	NA	3.63%	3.0%	4.2	21.5	21.5	na	na
Vectren Corp	VVC	Not Rated	4,273	51.61	NA	3.10%	1.2%	2.2	20.9	19.3	18.3	na
Average						3.04%	3.1%	4.3	20.2	18.8	17.7	16.7
Regulated Average						3.17%	2.8%	3.7	19.9	18.8	17.8	16.8
		Rating	Market Cap. (\$ in millions)	Price 7/21/2016	Price Target	Short Net Debt	Interest	Days to Cover	EV / EBITDA Multiple			
									2016E	2017E	2018E	
INDEPENDENT POWER PRODUCERS												
AES Corporation	AES	Neutral	8,303	12.60	11.00	27,700	2.0%	1.8	7.5	7.3	6.4	
Calpine Corporation	CPN	Buy	5,244	14.61	17.00	10,565	3.4%	2.9	8.6	7.9	7.5	
Dynegy, Inc.	DYN	Neutral	1,915	16.39	22.00	6,226	12.5%	2.1	8.9	9.6	6.0	
NRG Energy Inc.	NRG	Sell	4,579	14.54	15.00	18,568	5.9%	3.4	7.1	7.3	6.2	
Talen Energy Corp	TLN	Neutral	1,756	13.67	14.00	3,931	3.7%	0.9	7.1	9.0	10.9	
Average						13,398	5.5%	2.2	7.7	7.8	6.6	

Source: Company Filings, FactSet, and UBS Estimates. *Not Rated are entirely FactSet

Figure 2: Visualizing Potential 2Q Beat and Misses

BENCHMARKS		2Q15 Earnings Center		
S&P500	SPY	1.9%	2Q16 Performance	
Utilities Select SPDR	XLU	5.7%	2Q16 Performance	

COMPETITIVE INTEGRATED	Ticker	UBSe	Consensus	Expected Beat/(Miss)
American Electric Power, Inc.	AEP	\$0.88	\$0.88	0%
Dominion Resources	D	\$0.73	\$0.71	2%
Entergy Corp.	ETR	\$0.73	\$1.08	-33%
Exelon Corp.	EXC	\$0.58	\$0.55	5%
FirstEnergy Corp.	FE	\$0.53	\$0.54	-2%
NextEra Energy	NEE	\$1.67	\$1.53	9%
Public Service Enterprise Group	PEG	\$0.58	\$0.61	-5%
Sempra Energy	SRE	\$0.85	\$1.00	-15%
Average				-4.8%

REGULATED INTEGRATED UTILITIES	Ticker	UBSe	Consensus	Expected Beat/(Miss)
Ameren Corp.	AEE	\$0.50	\$0.51	-1%
Alliant Energy Corp.	LNT	N/A	\$0.35	N/A
Avista Corp	AVA	\$0.46	\$0.44	4%
CMS Energy	CMS	\$0.33	\$0.34	-2%
DTE Energy Co.	DTE	\$0.85	\$0.90	-6%
Duke Energy	DUK	\$1.05	\$1.01	4%
Edison International	EIX	\$1.00	\$0.99	2%
Great Plains Energy	GXP	N/A	\$0.42	N/A
Hawaiian Electric Industries	HE	N/A	\$0.40	N/A
PG&E Corporation	PCG	\$0.86	\$1.00	-14%
Pinnacle West Capital Co.	PNW	\$1.13	\$1.17	-4%
Portland General Electric	POR	\$0.46	\$0.44	6%
PNM Resources Inc.	PNM	N/A	\$0.38	N/A
PPL Corporation	PPL	\$0.50	\$0.53	-5%
SCANA Corp.	SCG	\$0.67	\$0.71	-5%
Southern Company	SO	\$0.72	\$0.69	5%
Westar Energy, Inc.	WR	\$0.55	\$0.53	5%
WEC Energy Group	WEC	\$0.57	\$0.56	1%
Xcel Energy Inc.	XEL	\$0.39	\$0.40	-3%
Average				-5.1%

REGULATED T&D UTILITIES	Ticker	UBSe	Consensus	Expected Beat/(Miss)
Consolidated Edison	ED	\$0.62	\$0.71	-12%
ITC Holdings Corp	ITC	\$0.57	\$0.56	1%
Eversource Energy	ES	\$0.63	\$0.65	-2%
Average				-4.1%

INDEPENDENT POWER PRODUCERS	Ticker	UBSe	Consensus	Expected Beat/(Miss)
AES Corporation	AES	\$0.15	\$0.20	-26%
Calpine Corporation	CPN	\$443	\$405	10%
Dynegy, Inc.	DYN	\$177	\$242	-27%
NRG Energy Inc.	NRG	\$668	\$678	-2%
Average				-25.9%

Source: Company Filings, FactSet, and UBS Estimates. *Not Rated are entirely FactSet

The PM Summary of 2Q Results

- **AES Corp:** *We do not expect a further revision to 2016 EPS guidance following recent negative adjustments to management's full year guidance ranges; we see recent Ohio headwinds as limiting 2Q improvement in shares.*
- **Ameren:** *Despite its discount, we see continued risks that AEE may see negative impacts in the lower rate cycle due its formulaic 30-year treasury yield exposure in Illinois, pending large Missouri rate case, as well as mark-to-market impact from ongoing FERC ROE complaints.*
- **American Electric Power:** *Shares continue to outperform as the market waits for updates on the sales process for the 'non-PPA assets' but a key question is whether public equity concerns about IPP valuations will impact the process. The 'PPA assets' are the more interesting debate where management has indicated it could advocate for Ohio re-regulation but this appears to be a post-election item. A more comprehensive regulated update is expected at EEI or with a 2017 Analyst Day when more legislative visibility is achieved.*
- **Avista Corp.:** *Avista is currently trading at ~20x 2018E, a 2x-turn premium to even SMid peers and is one of the most expensive utilities we track (MGE Energy trades at 22x, based on consensus estimates) and we continue to believe there are more attractive return opportunities elsewhere given the approximately average 4-5% EPS growth target.*
- **Calpine Corporation:** *We look for management to provide more details on the South Point transaction and explain why there is not a direct valuation read-through for the 'merchant' west and southeast portfolios. Texas has also been a hot topic lately following the latest disclosures from Energy Future Holdings (EFH) and the regional haze developments – as the prospects for near-term retirements have seemingly diminished we look for the company's response.*
- **CMS Energy:** *The prospects of new energy legislation in Michigan appears off-the-table in the near-term following the June recess. The challenge for 2017 will be educating new Representatives after the election cycle this Fall. Despite this setback, CMS has continued to outperform and still trades at a 10% premium, among the highest in the group due to management's track record of delivering on its above-average EPS growth rate in different cycles. We continue to see CMS as among the best positioned to maintain an above-average EPS growth rate, seeing valuation as our principle 'hold-up' on the stock.*
- **Consolidated Edison:** *The rate case is the key near-term focus and recent pushback of the hearing timeline suggests settlement talks are progressing as ED has historically done. We also look to the recently released REV track 2 document for indications of future rate structure, which includes both positive incentives and a mandated 10 year depreciation schedule for assets. We continue to struggle with the disconnect between the below-average EPS growth prospects and the valuation premium versus peers.*

- **Dominion Resources:** 2017 earnings is still a focal point with commodity weakness pointing towards a relatively flat profile despite accelerating in 2018+. A hedging update for Millstone could shore-up the outlook. Management's confidence in the dividend per share profile could help to orient investors beyond FY2 earnings.
- **DTE Energy:** Shares have been steadily outperforming since the March lows as confidence on the unregulated business outlook has grown, despite the failure of Michigan energy legislation to be approved. We continue to see DTE as attractively positioned.
- **Duke Energy:** Investors continue to debate whether DUK deserves a premium to peers – we continue to believe yes as it moves to a pure-play regulated utility and meets the demand for 'cheaper' defensive utility plays. Pricing on the Latin American divestiture is an important datapoint but we perceive the most investor caution around coal ash spending and the subsequent regulatory treatment. We think clarity here could be a significant driver for shares and the latest with the North Carolina is a key positive. We believe favorable regulatory treatment for coal ash could push the EPS growth profile towards the higher end of its 4-6% range, seemingly later in the decade.
- **Dynegy Energy:** Following the latest capacity auctions the attention is now on the potential asset sales that management has discussed and the synergy update for Engie. We caution that sales prices could disappoint on a \$/kW basis for CA and NY but an accelerated emphasis on reducing leverage should be well received.
- **Edison International:** Potential for a full SONGs case reopening remains one of the key questions in the near term but we see risk of a prolonged outcome as relatively limited. No substantial surprises are expected in the quarter and we see a relatively in line earnings number.
- **Empire District:** EDE and Algonquin have made important steps towards completing their pending merger with approval in Oklahoma and a settlement in Arkansas. The timeline in Kansas and Missouri is a bit longer-dated but we expect the companies to continue working with stakeholders to try and proactively address any issues.
- **Entergy Corp.:** We saw Entergy's recent Analyst Day as relatively more cautious but now we look for questions to revolve around the nuclear portfolio given the potential for incentive payments in New York for FitzPatrick, potentially facilitating a sale (currently negotiating with Exelon). While 2Q appears a headwind, sale of FitzPatrick would be a positive.
- **Eversource Energy:** We remain on the sidelines upon our latest review of shares, seeing too much uncertainty around the upcoming Supreme Judicial Court (SJC) decision for Access Northeast. Following the latest delay to the Northern Pass project, we see risk around negative EPS revisions heading into 2Q. Despite prospects for (positive) MA legislation next week, this would appear only incremental in execution of Northern Pass project.
- **Exelon Corp.:** The key at the August Analyst Day will be inspiring confidence in the regulated outlook (7-9% EPS CAGR expected to be rolled-forward rather than increased) while explaining why management believes its unregulated retail marketing business deserves a premium valuation – we remain skeptical on this latter point.

- **FirstEnergy:** We believe that new Distribution Modernization Rider structure (or some form, potentially better) will ultimately be approved; therefore, shares setup well into a ~Fall approval of the construct but there are still significant risks. We see the PUCO as undeterred by recent state Supreme Court rejections of similar structures and keen to provide support to its local utilities through a vehicle that does not face similar oversight risk from FERC. More broadly, we are more constructive on shares into a potential balance sheet fix update.
- **ITC Holdings:** Fortis has secured a minority investor for Fortis and is progressing with the regulatory approval process. The FERC review process is expected to be more critical than the state processes where the attention will be on intervenor filings. We expect deal close, consistent with our target price.
- **NextEra Energy:** Following the termination of the Hawaiian Electric transaction the focus turns to the Oncor process in Texas where management has explicitly indicated interest if the price is right. After the detailed update of NEER with 1Q16, investor attention turns to the significant rate case where we believe the risk of ROE erosion has increased following the latest step-down in US treasury rates.
- **NRG Energy:** As attention grows on the GenOn negotiation process, management has stated that it will be disciplined when dealing with creditors and will seek to preserve its balance sheet while working to offset dis-synergies. We see this as a potential near-term positive as a more disciplined line is articulated around GenOn heading into 2Q. We emphasize retail tailwinds from peers suggest potential for robust earnings.
- **PG&E Corp:** PCG continues to have an above-average risk profile today but we see a path towards real improvement as the company progresses through some of the more critical regulatory issues. For example, the possibility of a settlement in the 2017 General Rate Case (GRC) in coming weeks could meaningfully reduce regulatory risk. Ultimately we believe a discount to local peers is warranted but shares have been creeping higher on a relative basis. While 2016 guidance appears intact for a 2Q update following the GT&S proposed decision, we see risk here too.
- **Pinnacle West Capital Co.:** Expected decision in UNS rate case for July could provide read-throughs to PNW's July 1 filed rate case, and we look to value of solar docket to provide potential framework for proper solar remuneration – which could affect the outcome of PNW's sweeping changes proposed in the rate case. Overall, uncertainty heading into the election season and three vacancies on the ACC suggest increased possibility of an outlier outcome for APS's rate case. We remain on the sidelines here given election and rate case risk.
- **Portland General Electric:** Key questions remain focused around ultimate outcome for the Carty plant and whether POR's next renewables RFP (towards the ~50% by 2040 standard) can yield a fourth-in-a-row win for the company. Management's contingency plan in the event Carty is delayed appears solid and we continue to see value accrual from the recently passed renewables mandate in the state. Shift in tax policy could add some complications to the ~2018 target for a build-and-transfer timeline for new wind; we note a more challenging start to the RFP process given the effort for an expedited effort (before year-end 2016 to qualify for 100% PTC) as also garnering some doubts.

- **PPL Corp.:** *PPL has been the largest laggard among regulated utilities in 2016 (-10% underperformance) which we expected given its significant UK concentration. We believe the most significant challenge for investors right now is that investing in PPL inherently involves making a call on the GBP foreign exchange rate. We continue to believe that the story deserves to trade at a discount but we believe the sell-off is overdone but caution that investors will likely be slow to return to shares, particularly with the long-term guidance ranges at risk today.*
- **Public Service Enterprise Group:** *A key investor question that management will have to address is whether the weak eastern 2019/2020 PJM capacity auction results will persist. While concerns are wide-spread in the market, we believe that articulating why a path back to improvement for the load center will help restore confidence in the outlook.*
- **SCANA Corp.:** *Following our latest call with the SC PSC Office of Regulatory Staff and the latest disclosures about the VC Summer nuclear construction projects, we remain concerned about the construction timeline, particularly in light of the nuclear PTC eligibility. The availability of the fixed price option and continued regulatory support for the project are both positives but we think it is still pre-mature to believe that the story fully re-rates in 2016. That said, we still see the potential for a settlement with ORS and SCANA heading into the Fall hearings on the Fixed Price contract.*
- **Sempra Energy:** *Analyst Day yields no surprises as stays the course on 2020E 12% EPS CAGR. While mgmt did not necessarily provide tangible new products at the Analyst Day, SRE provided the first framework in sizing balance sheet and continued to articulate primarily new areas of utility growth.*
- **Southern Company:** *On a longer-term basis the question is whether large cap traditional safety names will begin to lose their reputation as safe havens as the earnings mix continues to evolve. While the latest M&A has been significant for Southern, we still see investors' attention focused on the large capital projects (Kemper IGCC and Vogtle nuclear) with Kemper entering a particularly critical month ahead of its target in-service later in 3Q. Commentary from the independent monitor for Vogtle construction was negative about the timeline, similar to the third-party outlook for SCANA's nuclear construction.*
- **Talen Energy:** *The 'go-shop' period expired on July 12th without a superior proposal and now management's focus is on completing the necessary regulatory filings to facilitate closing the transaction by YE16.*
- **WEC Energy:** *With no material rate cases expected in the near-term (WI no longer anticipated in 2016), the focus remains on incremental capex opportunities to address the capex 'cliff' in 2018 which management has committed to updating the outlook by EEI (November). While we do not expect a quantitative update on the capex 'backlog' on the 2Q call, we expect a continued discussion on the opportunity set available to offset the impact of bonus depreciation (already approximately half addressed)*
- **Westar Energy:** *The upcoming report (July 25th) from the Missouri PSC regarding the pending transaction will be a critical datapoint for the merger and pro-forma company outlook. We do not forecast any significant difficulty with Kansas approval but broader questions remain about the ability to retain \$150+Mn annual synergies in the long-run.*

[Please click here for the full 2Q16 Integrated Utilities Preview](#) – AEP, D, ETR, EXC, FE, NEE, PEG, SRE, XEL

[Please click here for the full 2Q16 Regulated Utilities Preview](#) – AEE, AVA, CMS, ED, DTE, DUK, EIX, EDE, ES, ITC, PCG, PNW, POR, PPL, SCG, SO, WEC, WR

[Please click here for the full 2Q16 IPP Preview](#) – AES, CPN, DYN, NRG, TLN I PJM, ERCOT, CAISO, NYISO, MISO, ISONE

Notable Beats and Misses

We distill the following from our PM summaries as key potential developments among our Power & Utility coverage.

Key Potential Beats

- **FE:** Delineation of a strategy to address the balance sheet, potentially via a de-emphasis of its genco could help re-rate shares, consistent with peer diversified utilities. Despite the meaningfully depressed position of its balance sheet, articulation of a strategy appears good enough to drive improvement.
- **POR:** While a less conventional beat, we see the timeline into next week's July 31 deadline to finish Carty as putting a substantial positive bias into shares as investors largely expect a modest delay already. We also are increasingly constructive on potential for its proposed wind RFP to move forward.
- **DUK:** We remain constructive on shares into a potential announcement of a sale of its Brazilian business; tailwinds remain constructive on pricing. Rather, with growing clarity on coal ash, etc, mgmt could well be in a position to reiterate EPS growth targets, even at the bottom end of its range, doubted already by Street.
- **CMS:** A strong quarterly beat, coupled with potential for developments on its Palisades nuclear plant in 2H leave us more constructive into 2H.
- **IPPs:** We suspect all three key IPPs (CPN, NRG, and DYN) each have their own positive factors going into the quarter. First, with DYN, we see final delineation of a new MISO construct to FERC could drive confidence in shares on its core coal portfolio. This is offset by meaningfully below Street estimates. As for NRG and CPN, results for both should be ahead of Street albeit with NRG's retail business positioned particularly well. As for NRG, a clear delineation that no equity will be issued for GenOn also skews constructively.

Key Potential Misses

- **ES:** We see clear downside risk mostly around the pending court decision on the fate of Access Northeast. We also remain concerned over continued negative revisions of Street estimates into 2Q related to the latest delay in Northern Pass recently. Lastly, we perceive some pressure on 2Q ests itself.
- **SCG:** We worry updates pertaining to the project skew more negatively as we continue to await any updates from Fluor around updated Payment milestones

and integrated schedule. We suspect SCG could drive a more cautious tone, similar to recent testimony on the SO sister project

- **PPL:** While clearly a meaningful discount to peers, we see clear downside 2017 and 2018 estimates. The question remains just how management will opt to characterize its 4-6% EPS growth rate given the latest sharp adjustments in F/X.
- **PCG:** We see modest downside risk as mgmt could be poised to revise to the bottom end, if not lower its 2016 EPS guidance range of \$3.65-3.85 following the outcome of its latest GT&S case – and risk of disallowed costs.
- **AEE:** We see clear downward pressure on EPS following the latest slide in 30-year treasuries as well as on authorized FERC ROEs in MISO. Moreover, the Missouri case remains an overarching headwind.
- **SO:** While already previewed in part to the Street via its regular updates to regulators, we emphasize downside risk from both latest delays for both Vogtle and ongoing execution at Kemper. Mitigating factors include the delineation of midstream growth opportunities, described as being worth 'a couple turns of EBITDA' against the latest asset acquisition valuation.

Our Top Picks Overall

We emphasize our favorite Power & Utility picks overall.

- **SRE:** We continue to see the risk/reward as the most compelling across the utility sector. While future growth opportunities remain unclear, mgmt projections appear abundantly conservative, with upside from both further balance sheet deployment, higher ROE prospects relative to buybacks assumed, and further upside from baseline utilities. See our latest note following the Analyst Day earlier this [week](#). Management's wider view of infrastructure development opportunities afford it a greater development opportunity set – such as Mexico and LNG, which provide substantially higher ROEs.
- **NEE:** We believe upside from its core renewable business provides a continued tailwind of positive revisions for shares. While a settlement in its pending FPL rate case remains among the biggest uncertainties for shares its track record of achieving such outcomes historically leaves us confident still. We see this as the biggest factor for shares in 2H, notwithstanding a strategic update on balance sheet deployment.
- **DTE:** We see the underperformance of shares amidst both an improving utility backdrop and midstream backdrop as quite surprising. Given the consistent results in recent years and quarters, we continue to expect shares to re-rate around a more streamlined business. We continue to perceive shares as among the cheapest equities relative to its above-average EPS growth.
- **DUK:** We think shares could well continue to get bid up amidst a wider anticipation for a truly stand-alone regulated utility outlook. We see DUK shares as among the most attractive 'defensive' stocks, with limited risk of further negative multiple revision.

Summarizing our EPS/PT Changes

Figure 3: US Power & Utilities — Changes to Earnings, Price Targets, and Ratings

Company	RIC	Price	Rating		Price Target		2016E EPS		2017E EPS		2018E EPS	
		20-Jul-16	New	Old	New	Old	New	Old	New	Old	New	Old
American Electric Po	AEP.N	69.35	Buy	Buy	77.00	72.00	3.70	3.70	3.85	3.84	4.10	4.06
Dominion	D.N	77.30	Neutral	Neutral	77.00	77.00	3.79	3.79	3.77	3.77	4.23	4.23
Entergy	ETR.N	79.96	Sell	Sell	75.00	70.00	4.86	4.86	5.56	5.54	5.15	5.07
Exelon	EXC.N	36.25	Neutral	Neutral	38.00	35.00	2.57	2.57	2.67	2.64	2.90	2.84
FirstEnergy	FEN	35.98	Neutral	Neutral	35.00	35.00	2.50	2.50	2.21	2.21	2.35	2.35
NextEra Energy	NEEN	127.21	Buy	Buy	140.00	134.00	6.32	6.32	6.77	6.75	7.12	7.09
Public Service Entrp	PEG.N	45.41	Buy	Buy	50.00	49.00	2.88	2.88	2.93	2.93	2.96	2.96
Sempra Energy	SREN	111.99	Buy	Buy	123.00	118.00	4.79	5.00	4.92	5.20	6.10	6.25
Xcel Energy Inc.	XEL.N	43.61	Sell	Sell	42.00	42.00	2.20	2.20	2.30	2.30	2.40	2.40

Source: Company Filings and UBS Estimates

Figure 4: US Regulated Electric Utilities — Changes to Ratings, Price Targets and Estimates

Company	RIC	Price	Rating		Price target		2016E EPS		2017E EPS		2018E EPS	
		19-Jul-16	New	Old	New	Old	New	Old	New	Old	New	Old
Ameren	AEE.N	52.34	Neutral	Neutral	53.00	49.00	2.48	2.48	2.78	2.80	2.95	3.00
Avista	AVA.N	43.38	Sell	Sell	39.00	36.00	2.06	2.06	2.13	2.13	2.23	2.22
CMS Energy	CMS.N	45.00	Neutral	Neutral	45.00	41.00	2.02	2.02	2.16	2.16	2.31	2.31
Consolidated Edison	ED.N	79.11	Sell	Sell	72.00	66.00	4.10	3.98	4.08	4.08	4.20	4.20
DTE Energy	DTE.N	98.05	Buy	Buy	108.00	104.00	4.93	4.93	5.35	5.35	5.83	5.83
Duke Energy	DUK.N	85.38	Buy	Buy	93.00	86.00	4.65	4.65	4.78	4.78	5.01	5.01
Edison International	EIX.N	77.11	Buy	Buy	79.00	79.00	3.88	3.88	4.16	4.16	4.35	4.35
Empire District	EDE.N	33.81	Neutral (CBE)	Neutral (CBE)	34.00	34.00	1.33	1.33	1.42	1.42	1.56	1.56
Eversource Energy	ES.N	58.09	Neutral	Neutral	61.00	61.00	2.98	2.98	3.08	3.08	3.26	3.26
ITC Holdings	ITC.N	46.24	Neutral (CBE)	Neutral (CBE)	48.00	46.00	2.05	2.05	2.30	2.30	2.52	2.52
PG&E Corp.	PCG.N	64.41	Neutral	Neutral	67.00	63.00	3.70	3.74	3.59	3.64	3.76	3.79
Pinnacle West Captl	PNW.N	79.68	Neutral	Neutral	80.00	74.00	4.00	4.05	4.16	4.19	4.52	4.54
Portland General	POR.N	44.05	Buy	Buy	49.00	46.00	2.19	2.19	2.40	2.40	2.60	2.60
PPL Corp.	PPL.N	37.17	Buy	Buy	41.00	41.00	2.33	2.34	2.41	2.43	2.49	2.55
Public Service Entrp	PEG.N	45.85	Buy	Buy	49.00	49.00	2.88	2.88	2.93	2.93	2.96	2.95
SCANA Corp.	SCG.N	73.70	Neutral	Neutral	72.00	72.00	3.95	3.95	4.19	4.19	4.38	4.38
Southern Company	SO.N	53.62	Sell	Sell	51.00	45.00	2.83	2.83	2.85	2.85	2.97	2.97
WEC Energy Group	WEC.N	64.17	Neutral	Neutral	63.00	58.00	2.94	2.94	3.12	3.12	3.33	3.33
Westar Energy	WR.N	56.34	Neutral	Neutral	60.00	60.00	2.40	2.40	2.53	2.53	2.65	2.65
Xcel Energy Inc.	XEL.N	43.79	Sell	Sell	42.00	39.00	2.20	2.20	2.30	2.30	2.40	2.40

Source: Company Filings and UBS Estimates.

Latest Thoughts on Integrated Utility Space

We present below key themes on the integrated space heading into 2Q results.

- (1) **The 'Bailouts' are Coming?** Confidence in Restructured Markets Gives way to Compensation. Looking towards 2Q, we expect the primary focus for diversified utilities will migrate towards the potential for a litany of restructured states to step-up in an effort to 'save' their baseload coal and nuclear assets amidst continued pressure from lower natural gas prices. While Ohio has garnered the most substantial interest this year, we note efforts exist now across IL, NY, and CT, with nascent efforts underway in PA and NJ. While earlier efforts to address market concerns earlier in the decade saw NJ and MD attempt to push new supply contracts, the latest focuses on retaining largely nuclear generation in an effort to maintain a stable base with regard to carbon. We believe sector sentiment could yet pivot more constructively should management's become more confident of prospects for continued of real developments in coming weeks on the back of NY success (NY's ZEC proposal is due to be voted by wider NY PSC on August 1st).
- (2) **The PJM auction aftermath – and more rationalization.** With 2Q the first call following the PJM capacity auction, we see the call as an important update around further cost cutting. While we would not expect formal commitments on further asset rationalization yet, it could be a possibility; rather than lowering costs amidst a meaningful ramp down in capacity revenues in the 2019/2020 period. The question remains how clear companies will be in providing an update view of their cleared MWs – and importantly implications on meaningful stepdown in generation business FCF. We tie the continued reduction in capacity revenues for Ohio generators, like FE, who continue to benefit from premium ATSI revenues of late; the PJM decline only emphasizes the prospects for a need for hybrid utilities to divest their generation businesses amidst an effort to grow EPS and DPS in a stable, consistent manner.
- (3) **What exactly is a 'Diversified' utility? We see an expanding bucket of diversified 'Infrastructure' utilities.** While historically companies were deemed 'diversified' when they typically held merchant generation assets, the latest trend for companies such as SO and ED to expand into gas midstream assets offers a more nuanced answer of what a 'Diversified' Utility entails. Rather, we see this Infrastructure list as potentially expanding away from the typical names (D, SRE, and NEE); we believe peers have noted their relatively higher trading multiples and above-average EPS growth as conventional electric utility growth opportunities have continued to abate. We would not be surprised to see the category of was known as a 'Diversified' utility to be largely redefined in coming years.
- (4) **Nearing the end of the Path for Hybrid Generators:** Focusing on the likes of EXC, PSEG, ETR, and FE, which continue to own meaningful merchant generation assets, we see all of these companies as effectively articulating strategies to either de-emphasize their commodity exposure via growth with only contracted assets (EXC) or the likely broader eventual divestment or deeming as non-core of their existing merchant assets. We expect 2Q to prove critical in providing near finality on articulating future strategies.

- a. Our primary focus will be FirstEnergy, whose 4Q timeline to provide a clear path to rating agencies on its go forward strategy to de-lever to keep its investment grade rating. We believe the 2Q call could provide the latest glimpse – and the most important strategic development – in our coverage universe. While the CEO's stated strategy emphasizes FE's regulated profile, the question will be just how far is willing to push this thesis? The agencies are providing a strong incentive to completely abandon the generation strategy with a meaningfully lower FFO/Debt threshold (-3% latitude) under a pure T&D risk profile, translating to meaningfully less equity.
- b. Beyond this company, we look for EXC to leverage its Analyst Day to emphasize its latest commitment to focus narrowly on 'contracted' generation assets in an effort to limit any new exposure to merchant generation; this would include the latest potential Fitzpatrick acquisition from ETR given the NY ZEC construct in place.

(5) Pension in focus as interest rates take their latest step lower

The pension mark-to-market weighs on FirstEnergy (FE) particularly hard and further complicates leverage story:

As of 12/31/15 FE's pension was only 61% funded versus a historical average of 75-80% for utilities. US treasury rates have declined 80-100bp since that point which could create even more earnings and funding pressure for management. Management disclosed in its 10K that it could meet the upcoming pension obligation with a combination of equity and cash; however, management previously indicated that it has no plans to meet the pension funding deficit with FE shares.

Figure 5: FE Pension Analysis

FE Pension Analysis (\$Mn)			
	2016	2015	Delta
Liability	(8,704)	(8,889)	185
Assets	5,338	5,822	(484)
Net Liability	(3,366)	(3,067)	(299)
2016 Min Funding	381	324	57
2017 Min Funding	N/A	555	N/A
Expected Return %	7.50%	7.75%	-0.25%
Discount Rate %	4.50%	4.25%	0.25%
*\$160Mn of the \$381Mn 2016 obligation contributed as of Feb			
Increase in Net Periodic Benefit Cost Sensitivities			
-25bp Discount Rate		292	
25bp Return		14	

Source: Company Filings

Figure 6: 30Yr US-Treasury Yield



Source: FactSet

Another impacted company is Entergy (ETR) where we estimate a 100bp change in the discount rate could have a +/- \$0.06 EPS impact, relative to \$4.20-\$4.50 utility, parent, & other guidance. We estimate a 25bp decrease in the discount rate would cause the 2015 qualified projected benefit obligation and accumulated postretirement benefit obligation to increase by \$228Mn and \$51Mn, respectively. Peer merchant nuclear operator Exelon also has exposure to declining interest rates via its pension obligations. We estimate a 50bp reduction in the discount rate would cause an \$113mn increase in pension & other postretirement benefit costs for 2015 while the total pension and other postretirement benefits obligation would increase

\$1.3Bn. We believe declining interest rates also can increase nuclear retirement obligations and potentially compel additional capital/parent guarantees for any projected shortfalls in the nuclear decommissioning trusts (NDTs). [Further details are available here.](#)

Looking at Leverage Metrics More Closely

Amidst the focus across the sector on improving risk profiles for rating agency purposes, we contrast at least S&P's quoted FFO/debt metrics across the sector to provide context. Seeing these diversified names as among the most widely ranging in terms of risk profile and existing credit metrics, we though approach it to contrast. We emphasize the business risk profile for the Genco remains just Strong according to S&P, emphasizing the wide range between FE and its peers. We continue to perceive a willingness and ability to lever up across the sector, largely as a function of reduced Business Risk profiles shifting to Excellent under new outlooks.

Figure 7: S&P Ratings for Diversified Utilities

S&P Ratings/Metrics					FFO/Debt				
	Corp Debt Rating	Outlook	Business Risk	Financial Risk	2014A	2015	2016E	2017+	Downside Scenario
True Genco/Diversified									
PEG	BBB+	Stable	Strong	Intermediate	27.7%	27-28%	23-24%		FFO/Debt <20% and Debt/EBITDA>3.5X
FE	BBB-	Negative	Strong	Significant	~12.5%	13.0%	11-13%		FFO/Debt <12%
EXC	BBB	Stable	Strong	Significant			23-25%	23-26%	FFO/Debt<18% Post acquisition
ETR (metrics from AD)	BBB	Positive					21% (Q1)	... Target: 13-23%	
Infrastructure Names									
D	BBB+	Stable	Excellent	Significant			15-17%		FFO/Debt<15% Consistently
NEE	A-	Stable	Excellent	Intermediate		26.0%	25-26%	25-26%	FFO/Debt <25% or business risk increases
SRE	BBB+	Stable	Excellent	Significant	14.6%	15-17%	15-17%		FFO/Debt <15%

Source: Company reports

Latest Thoughts on Regulated Utility Space

We present below key themes on the regulated space heading into 2Q results.

(1) Valuations Supported by Global Rates: Average relative and absolute P/E multiples are at or near all time highs for many of the regulated names but we see limited support for downside arguments in the face of plethora historic lows and negative rates around the world. This stands in contrast to largely [depressed power multiples](#). We note international rates have a less drastic correlation (-0.62 and -0.44 vs -0.72 in the US) of relative P/E to interest rates, but continue to hear evidence of foreign asset ownership in US power assets and by extension, US utility stocks.

(2) Capital Structure Increasingly Debt Heavy: Investors continue to ask about potential risks to the capital structure for ratemaking purposes following the developments in states including Missouri, Louisiana, and Texas but we do not see a wide-spread trend. Companies are increasingly adding leverage to their consolidated capitalization structures; however, we note leverage is still lower than it was earlier in the decade, for context. We agree that there is risk that regulators increasingly 'look-through' to the Holding Company capital structure rather than just the Operating Company but see this as a lower probability event for most.

Paying ever closer attention to credit metrics. Overall, we sense investors are all the more apt compare FFO/Debt metrics across companies and are increasingly aware of relative positions of Holding company leverage. We think this focus will continue, particularly amidst efforts to re-rate risk profiles to drive 'required' minimums from the rating agencies lower. We emphasize agencies would appear open to 10% FFO/Debt for purely regulated companies (T&D) in low risk jurisdictions for investment grade metrics.

(3) What's the next move in the gas expansion story? Following the latest move for Southern to enter the midstream space (after just closing on its gas utility acquisition, AGL), we see prospects for the sector to continue to 'gas up'. While we continue to see gas utilities as the most logical targets (with lower risk profiles, and above-average EPS growth profiles predicated on safety related spend), we see merits to continue this diversification into the gas midstream sector. We believe many more 'utilities' will be poised to redefine as diversified 'infrastructure' companies in coming years (SO and ED are just the latest examples). We caution that utility investors have largely ignored the underlying recontract and commodity risks embedded in the pipeline expansion. Further, we find it notable that assets that are eligible for tax-advantaged MLP structures are still ending up in taxable C-Corp utility structures. *Overall, we see no reason to expect this trend to slow as utilities maintain incremental leverage capacity to do acquisitive regulated deals.*

(4) Wind remains the focus, but limited details. Following the latest IRS guidance on the 'start of construction' language extension out to 4-years after their 2016 expiration of Production Tax Credits (PTCs) for wind, we look for utilities to discuss their latest development plans. We note XEL and other regulated stories have discussed leveraging the repowering opportunity available to them by buying out PPAs poised to retire. The overarching

question remains the pace of RFPs/procurement alongside the potential to acquire existing regulated assets.

(5) Pension in focus as interest rates take their latest step lower

The pension mark-to-market weighs on FirstEnergy (FE) particularly hard and further complicates leverage story: As of 12/31/15 FE's pension was only 61% funded versus a historical average of 75-80% for utilities. US treasury rates have declined 80-100bp since that point which will create even more earnings and funding pressure for management. Management disclosed in its 10K that it could meet the upcoming pension obligation with a combination of equity and cash; however, management previously indicated that it has no plans to meet the pension funding deficit with FE shares.

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Source: Company Filings

Figure 9: 30Yr US-Treasury Yield



Source: FactSet

Another impacted company is Entergy (ETR) where we estimate a 100bp change in the discount rate could have a +/- \$0.06 EPS impact, relative to \$4.20-\$4.50 utility, parent, & other guidance. We estimate a 25bp decrease in the discount rate would cause the 2015 qualified projected benefit obligation and accumulated postretirement benefit obligation to increase by \$228Mn and \$51Mn, respectively. Peer merchant nuclear operator Exelon also has exposure to declining interest rates via its pension obligations. We estimate a 50bp reduction in the discount rate would cause an \$113mn increase in pension & other postretirement benefit costs for 2015 while the total pension and other postretirement benefits obligation would increase \$1.3Bn. We believe declining interest rates also can increase nuclear retirement obligations and potentially compel additional capital/parent guarantees for any projected shortfalls in the nuclear decommissioning trusts (NDTs). [Further details are available here.](#)

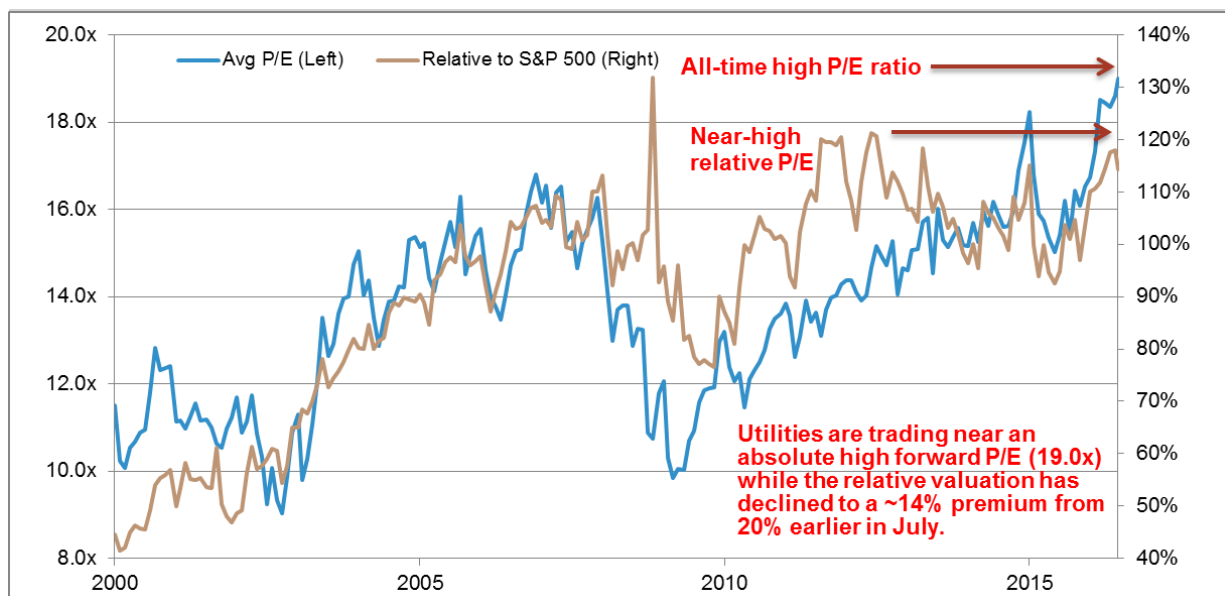
Interest Rate Views and Macro Views

US utilities are now trading at 19.0x forward P/E after having rallied further following the UK Referendum vote but have pulled-back marginally recently. As we show later in the note, the majority of utilities we track hit new 52-week highs in the last few weeks but the relative valuation have started to decline as the S&P 500 has outpaced the group. For example utilities were trading at a 20% premium to the S&P 500 earlier in July but the relative premium has declined to 14%, still above average but a sharp-pull back.

We continue to see further upside to the regulated utility sector, seeing the lower rate environment as supportive of yet higher valuations vs. the ~20% peaks on a relative basis seen in 2011 and 2012.

[Please click here for further macro thoughts.](#)

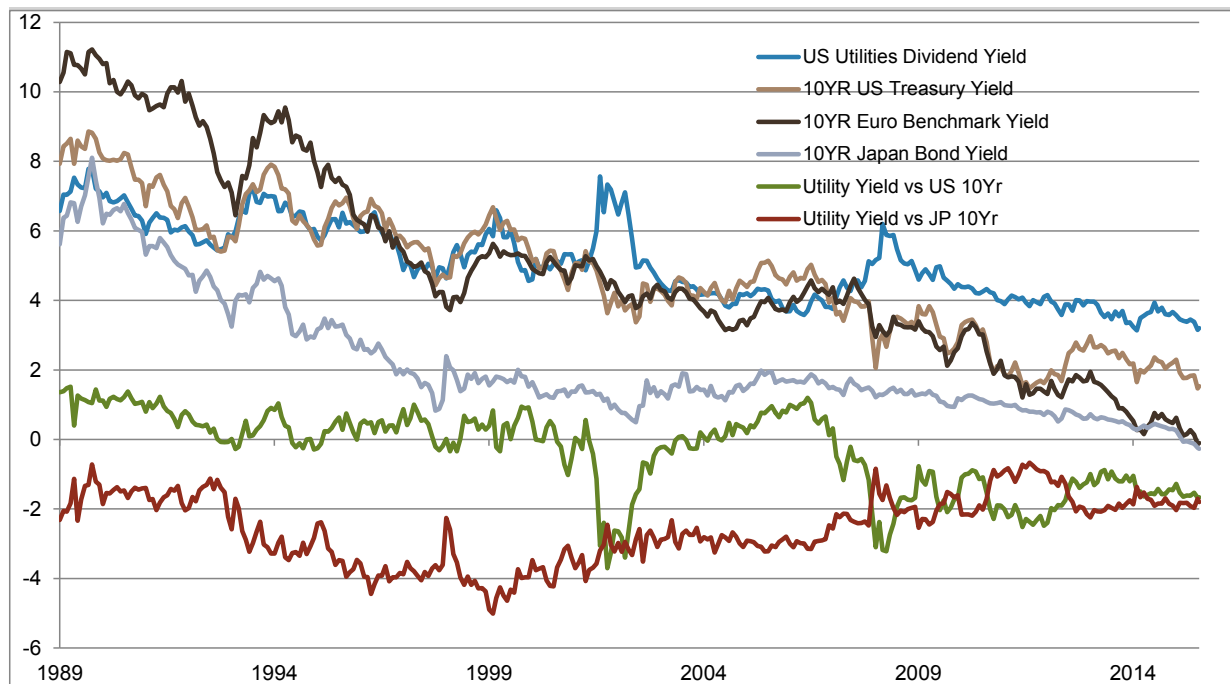
Figure 10: Electric Utilities Absolute and Relative P/E Multiples



Source: FactSet

Approaching the debate from a global perspective

Figure 11: Comparison of US Utilities Dividend Yields Versus Global Benchmarks (%)



Source: FactSet

We start our analysis by comparing the dividend yield for US electric utilities to the ten-year government interest rates for United States, Euro Zone, and Japanese benchmarks. The dividend yield on US electric utilities has been below 4% consistently since 2012 but has been steadily declining with the yield rapidly approaching 3.0% today, among the lowest we have seen (only late 2014/early 2015 were lower). In examining the spread between dividend yield and the US treasury yield, we have seen a 150bp average premium for dividend yields over treasury yield since 2015, down from over 200bp in 2012. After the 'Leave' vote in the UK Referendum the spread expanded to 170bp; again, while this is above-average for recent history, it is not unprecedented.

Given that the historical linkage has been relatively robust we continue to expect this relationship to hold with utilities as a group trading largely as a function of interest rate expectations. Please see the correlation between relatively utility P/E and treasury yields in the next Figure. We include foreign interest rates as a comparison to show that even as the dividend yield on US utilities approaches an all-time low, it represents a premium to the local government benchmarks. For example, the spread for US treasury yields and for Japan bond yields versus US utilities dividends is quite similar (150-200bp).

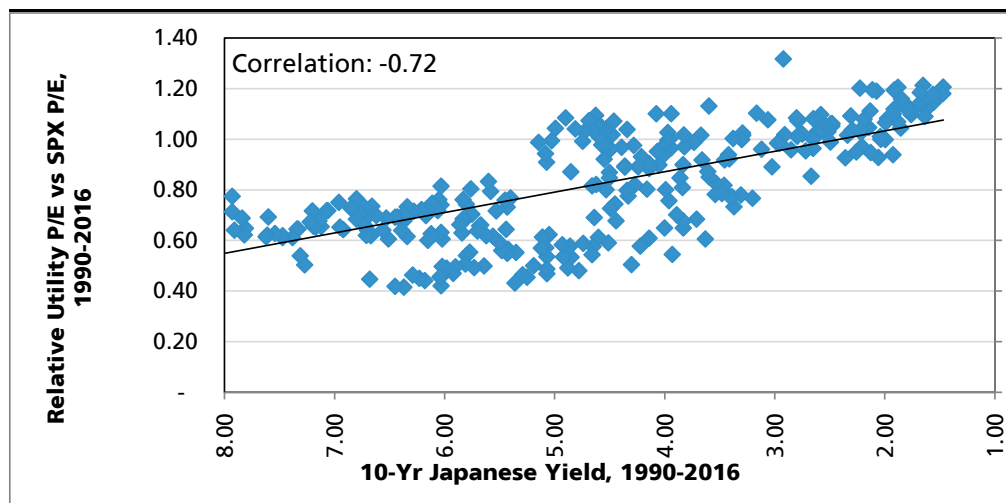
Global comparisons matter all the more: We argue that lower global rates contribute to finding renewed highs in utility valuations, with today's JPY yield levels materially below those below 2012, the period where US rates last hit their lows. We emphasize foreign capital continues to play a fairly explicit role in funding private equity investments in the Power sector for new gas plants in PJM, as well as in driving bids for select utilities (CNL for ex.). In contrast, explicit flows into US equity markets from global investors is much more opaque, effectuated via investments in US and foreign money managers alike. Net-net, equivalent

The dividend yield on US utilities has been steadily declining and is now solidly below 4%; however, the spread against US treasury yields has been relatively constant as the rates have largely moved in tandem recently.

Interestingly the spread vs US Treasuries and Japanese bonds has tightened as well over time.

valuations from 2012 should be higher vs. global peers even vs. a flat treasury environment.

Figure 12: Average Relative Utility P/E (to SPX P/E) vs 10-Year Treasury Yield, 1990-2016

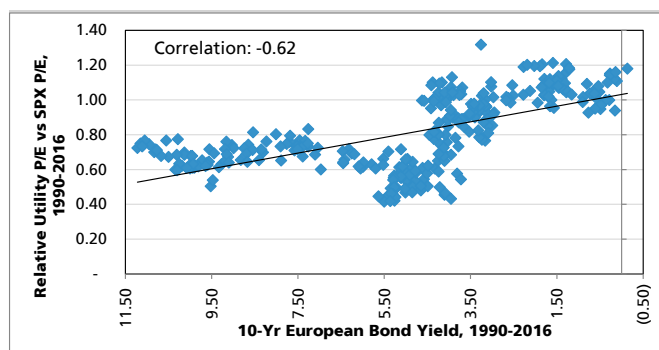


Source: FactSet

Global rates matter as well

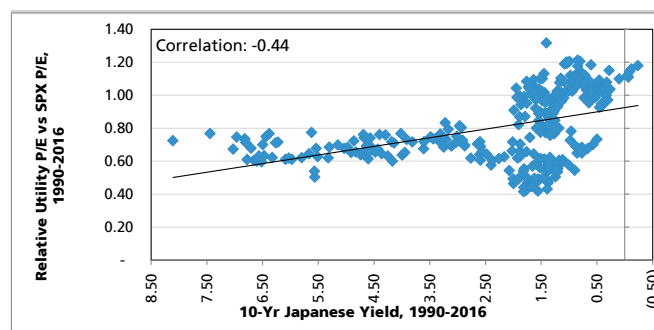
While domestic interest rates demonstrate significant historic correlation to relative P/E, we note further read-throughs from international bonds. We believe low or negative rates may be encouraging international investment in both US power assets and not some level of negative correlation between rates and outperformance, albeit to a lesser extent vs domestic rates. Japanese correlation is likely skewed given historic low interest rate environment but European bonds suggest higher correlation and stronger potential for flows into domestic US assets.

Figure 13: Avg Utility P/E Vs 10 Yr European Bonds



Source: FactSet

Figure 14: Avg Utility P/E Vs 10 Yr Japanese Bonds



Source: FactSet

UBS House View: No US rate increase in September

The question is whether significant Federal Reserve tightening can occur following the UK's decision to leave the European Union. The UBS Macro team now believes that it is unlikely that the Federal Reserve will increase the Federal funds rate 25bp at its September 20-21 Federal Open Market Committee (FOMC) meeting but still believes the Fed will tighten 25bp at the December 13-14 FOMC meeting. Prior to the UK referendum the UBS House View was that the yield on the US 10-year Treasury would rise to 2.0% by year-end 2016 and to 2.3% by year-end 2017. Based on the strong historical correlation between the 10-year Treasury yield and relative utility pricing (see charts above), this implies a relative utility P/E to the S&P 500 P/E of **~1.07x by year-end 2016 and ~1.00x by year-end 2017, without adjusting for the global rate environment. Compared to the current 1.20x, this further implies -11% underperformance for regulated utilities vs the S&P 500 through year-end 2016 and -20% through year-end 2017.** Admittedly, this is a rough projection dependent on historical correlations that may not be fully realized given the wide spreads utility dividend yields currently enjoy vs government bonds. In other words, we continue to believe any future underperformance of utilities is likely to be tempered by dividend yield support until rates rise substantially.

On a fundamental basis the UBS team still expects 2% real GDP growth in the US for the balance of 2016 and 2.5% in 2017 with a stronger dollar and less export activity offset by lower long-term interest rates. A strong US economy similarly bodes well for electric sales growth in the US although we believe regions dependent on exports such as the southern US could be relatively disadvantaged.

The latest from our Economics team are available below:

[7/6/16 Global FX Atlas: Which views remain after Leave?](#)

[6/29/16 UK: Overwhelmed by Uncertainty \[GBP Forecasts\]](#)

While we believe the macro backdrop is positive for utilities, we discuss a strategy for those concerned about a sector rotation. When looking for attractive names among utilities we highlight equities trading at a discount including DTE and POR. We are less disposed to like regulated utilities trading at material premiums such as ED, SO, and XEL; however, we highlight that these are the traditional safety names. We believe another factor to consider is that companies with significant parent leverage could be challenged in a rising interest rate environment such as Entergy (ETR) and FirstEnergy (FE).

What are the implications of the continued low interest rate environment?

After hitting recent lows in the 10-year treasury, we revisit the potential implications of what low rates mean for the sector: both good and bad.

ROE Risks back on the table? We see ongoing rate cases this year as subject to continued ROE risk. We reiterate ED as among the more exposed to this theme given the more formulaic approach taken by the New York Public Service Commission (PSC) staff. As we mentioned previously, Ameren and Exelon both have risks from lower ROEs in Illinois due to the EIMA. We think Ameren could see more risk here with a 3.2% 30-Yr Treasury yield embedded in its 2016 guidance (vs 2.1% today); we estimate every 50bp change would impact EPS by ~\$0.025 (1% of 2016E EPS). The long-term EPS guidance range of 5-8% through 2020E is also seemingly predicated on a recovery in US

The UBS Macro team no longer expects a Fed hike at September FOMC meeting following the UK Referendum.

The Macro team sees downside to its GDP forecasts.

If appetite for risk returns, we believe large cap US utilities could be disproportionately impacted by rotation out of utilities including utilities such as Southern Company (SO).

Companies with FERC jurisdiction transmission assets could face more risk from declining interest rates given the multiple challenges we have seen to ROEs.

Treasury yields, at least relative to reduced levels of late. We believe other large rate cases, such as NextEra's Florida Power & Light (FPL) rate case could be under scrutiny as well with its last case struck during a period of low rates as well. The national average authorized ROE in 2016 is ~9.7% and we believe there could be some incremental pressure lower. We see further risk in transmission, seeing yet another round of FERC reviews in New England (ISO-NE) as well as potentially MISO as adding to the risk factors. We believe the equities most exposed here include ITC Holdings (being purchased by Fortis), Eversource (ES), and Ameren.

What is the risk that the cost of capital is adjusted in California?

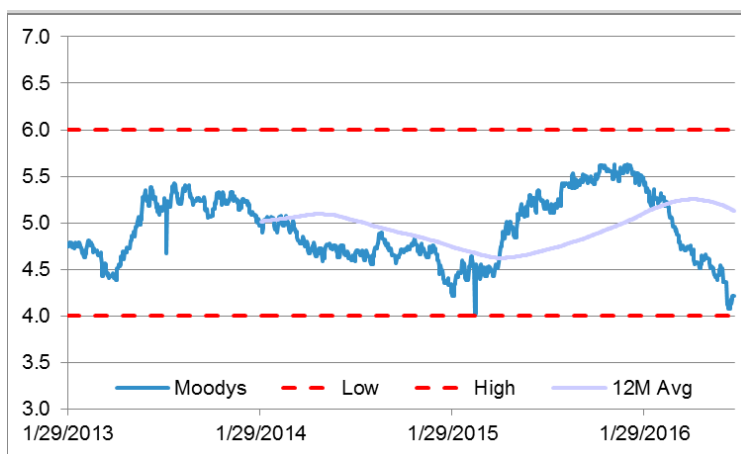
We think unlikely before the April 2017 review. Currently EIX's California Public Utilities Commission (CPUC) return on equity is 10.45% and will remain at that level unless the trailing-twelve month Moody's Baa index goes outside of the 4-6% band. While we do not believe that the index will go outside of the bands in the near-term, there is a risk intervenors could advocate for a lower return level and/or a more restrictive adjustment mechanism.

The Moody's index is currently at 4.54% and the trailing average is 5.2%, well above the 4% floor trigger but the absolute level is at its lowest point YTD. A joint petition was approved in February 2016 by the CPUC which extended the review period for the ROE mechanism by one-year. We think a further extension could be a possibility, particularly if Baa appears close.

With the index average still over 5% we do not believe investors are pricing in a lower California return on equity. Additionally, following the recent joint petition to extend the ROE mechanism we believe that investors see another extension as a possibility

We emphasize a further delay in the California case would be a September datapoint

Figure 15: Moody's Baa Index Relative to 4-6% 'Bands'

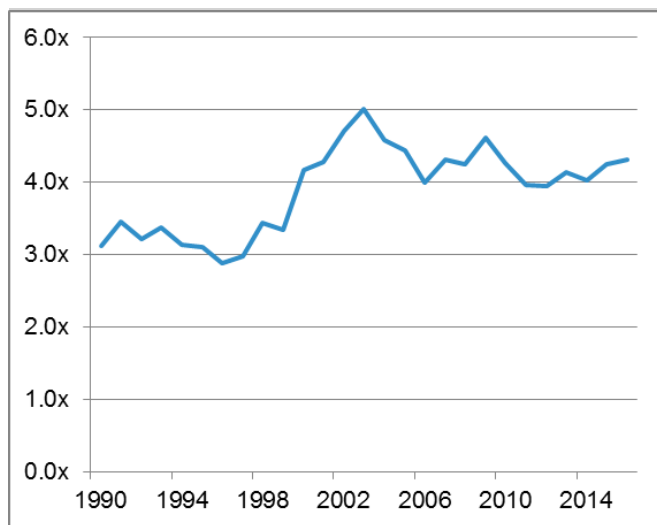


Source: FactSet and Company Filings

- **Capital structure likely remains untouched:** Investors continue to ask about potential risks to the capital structure for ratemaking purposes following the developments in states including Missouri, Louisiana, and Texas but we do not see a wide-spread trend. Companies are increasingly adding leverage to their consolidated capitalization structures; we put the trend in context below to show that leverage is still lower than it was earlier in the decade. We agree that there is risk that regulators increasingly 'look-through' to the Holding Company capital structure rather than just the Operating Company but see this as a lower probability event for most.

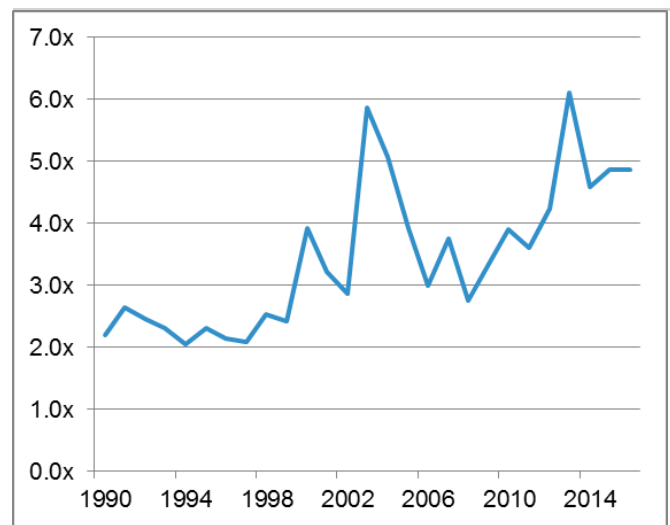
The current environment remains largely devoid of conversation on adjustments to authorized equity ratios with a few notable exceptions.

Figure 16: Utility Average Debt / EBITDA



Source: FactSet

Figure 17: DUK Debt / EBITDA

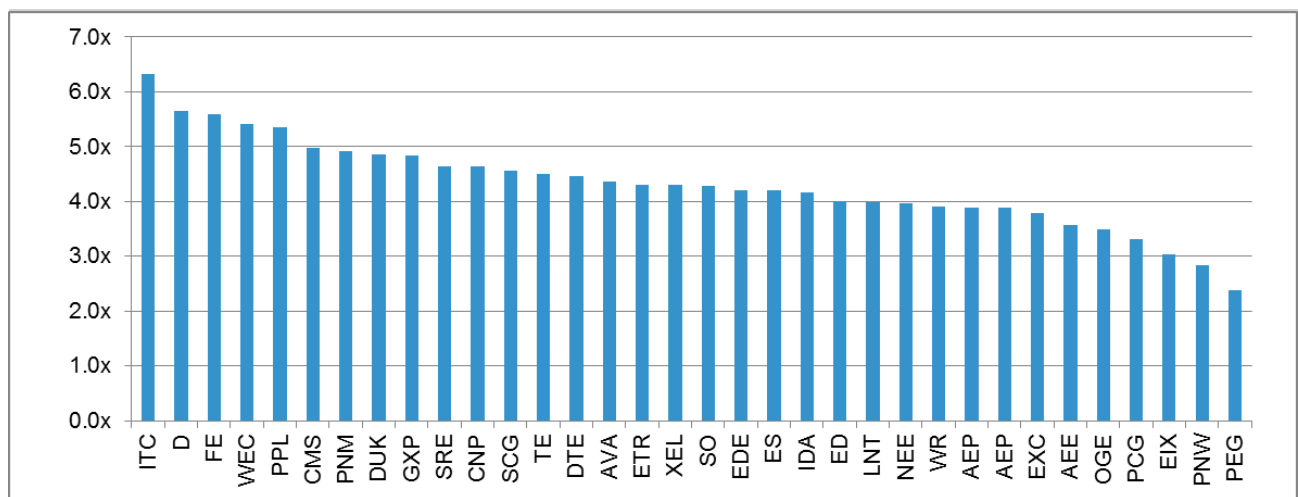


Source: FactSet

For example, Duke Energy has seen its debt / EBITDA leverage increase by 1.4x since 1990, among the most significant increases for regulated utilities as the company has executed on M&A during the period. Broadly we saw leverage increase in the early 2000s, peaking at 5x in 2003 before stabilizing around 4x.

Since 2012 we have seen a steady 10bp annual increase in leverage for the group to 4.3x today from 3.9x. Below we show consolidated Debt / EBITDA for select companies.

Figure 18: Utility Debt / EBITDA: 4.3x Average



Source: FactSet

- **Deal-making could continue to happen:** With the low rate environment continuing longer than some had predicted, we believe the conditions that supported the high degree of M&A activity we saw in 2014-2016 remain present. We would expect companies interested in M&A that have not executed on a deal could still be searching for candidates. Although premiums have been rich with deals being executed at 20-22x forward P/E, access to cheap debt capital can help boost returns.

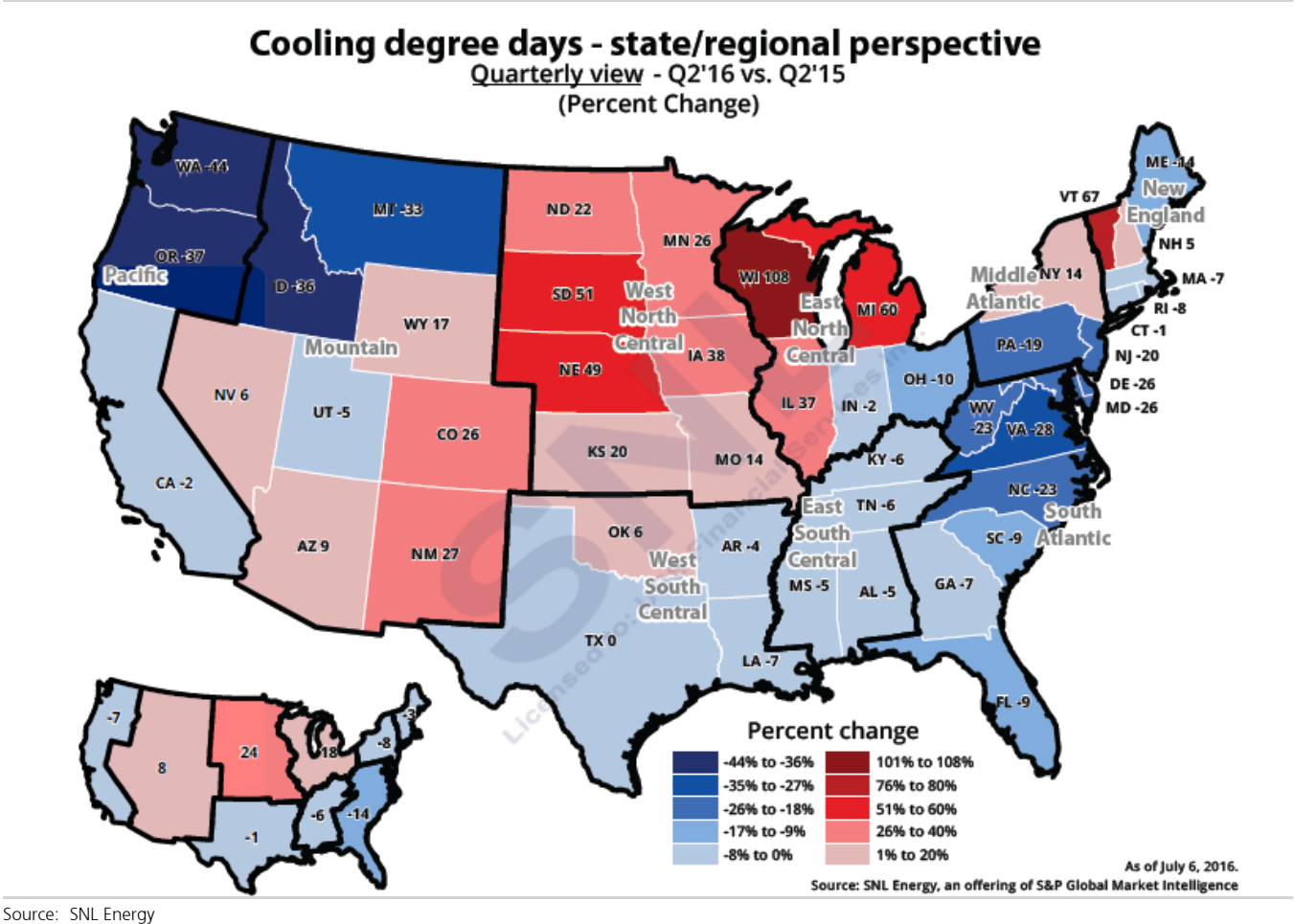
We would expect that bidders who have been unsuccessful would remain interested in any subsequent M&A opportunities.

We caution that while some companies had taken cursory looks, the risk remains for further deals to transact. We would continue to expect small-and-mid cap (SMids) to continuing trading at premium valuation versus their peer large-caps. [Further details are available here.](#)

Weather: Less of a factor but a net negative in East/Positive in Central

As shown below cooling degree days (CDDs) were lower across YoY in 2Q16 across most of the east coast while the midwest saw a solid increase in temperatures in June. We caution that in the Central some of the higher CDDs observed in the quarter are partially offset by lower gas demand earlier in 2Q16 for companies with both electric/gas exposure.

Figure 19: Quarterly Weather Map: Cooling Degree Days 2Q16 vs 2Q15: State/Regional Perspective (% change)



Source: SNL Energy

Regulatory Update

Key Rate Cases to Watch:

Figure 3: Select Pending Electric Rate Cases

Company	Parent Company Ticker	State	Case Identification	Service	Case Type	Rate Increase (\$M)	Return on Equity (%)	Action Likely By
Florida Power & Light Co.	NEE	Florida	D-160021-EI	Electric	Vertically Integrated	1,337.7	11.50	10/27/2016
Pacific Gas and Electric Co.	PCG	California	A-13-12-012 (GT&S)	Natural Gas	Transmission	548.0	NA	9/30/2016
Consolidated Edison Co. of NY	ED	New York	C-16-E-0060	Electric	Distribution	479.6	9.75	12/31/2016
Arizona Public Service Co.	PNW	Arizona	D-E-01345A-16-0036	Electric	Vertically Integrated	433.4	10.50	6/1/2017
DTE Electric Co.	DTE	Michigan	C-U-18014	Electric	Vertically Integrated	344.0	10.50	2/1/2017
Northern States Power Co. - MN	XEL	Minnesota	D-E-002/GR-15-826	Electric	Vertically Integrated	297.1	10.00	6/1/2017
Brooklyn Union Gas Co.	-	New York	C-16-G-0059	Natural Gas	Distribution	290.0	9.94	12/31/2016
Pacific Gas and Electric Co.	PCG	California	A-15-09-001 (Elec)	Electric	Vertically Integrated	270.5	NA	12/31/2016
Consumers Energy Co.	CMS	Michigan	C-U-17990	Electric	Vertically Integrated	225.4	10.70	3/1/2017
Massachusetts Electric Co.	-	Massachusetts	DPU-15-155	Electric	Distribution	211.3	10.50	9/30/2016
Union Electric Co.	AEE	Missouri	C-ER-2016-0179	Electric	Vertically Integrated	206.4	9.90	4/30/2017
DTE Gas Co.	DTE	Michigan	C-U-17999	Natural Gas	Distribution	182.9	10.75	12/19/2016
KeySpan Gas East Corp.	-	New York	C-16-G-0058	Natural Gas	Distribution	174.7	9.94	12/31/2016
Consolidated Edison Co. of NY	ED	New York	C-16-G-0061	Natural Gas	Distribution	158.9	9.75	12/31/2016
Pennsylvania Electric Co.	FE	Pennsylvania	D-R-2016-2537352	Electric	Distribution	158.8	11.30	1/27/2017
Oklahoma Gas and Electric Co.	OGE	Oklahoma	Ca-PUD201500273	Electric	Vertically Integrated	149.5	10.25	7/31/2016
New Jersey Natural Gas Co.	NJR	New Jersey	D-GR-15111304	Natural Gas	Distribution	147.6	11.00	8/17/2016
Jersey Cntrl Power & Light Co.	FE	New Jersey	D-ER-16040383	Electric	Distribution	142.1	11.20	1/27/2017
Metropolitan Edison Co.	FE	Pennsylvania	D-R-2016-2537349	Electric	Distribution	140.2	10.90	1/27/2017
Commonwealth Edison Co.	EXC	Illinois	D-16-0259	Electric	Distribution	139.6	8.64	12/9/2016
Northern IN Public Svc Co.	NI	Indiana	Ca-44688	Electric	Vertically Integrated	126.6	10.75	7/27/2016
Potomac Electric Power Co.	EXC	Maryland	C-9418	Electric	Distribution	126.6	10.60	11/15/2016
Public Service Co. of NM	PNM	New Mexico	C-15-00261-UT	Electric	Vertically Integrated	123.5	10.50	9/1/2016
Tucson Electric Power Co.	FTS	Arizona	D-E-01933A-15-0322	Electric	Vertically Integrated	109.5	10.35	1/1/2017
United Illuminating Co.	-	Connecticut	D-16-06-04	Electric	Distribution	100.2	9.92	12/31/2016
West Penn Power Co.	FE	Pennsylvania	D-R-2016-2537359	Electric	Distribution	98.2	10.90	1/27/2017
Kansas City Power & Light	GXP	Missouri	C-ER-2016-0285	Electric	Vertically Integrated	90.1	9.90	4/30/2017
Potomac Electric Power Co.	EXC	District of Columbia	FC-1139	Electric	Distribution	85.5	10.60	7/31/2017
Atlantic City Electric Co.	EXC	New Jersey	D-ER-16030252	Electric	Distribution	84.4	10.60	12/22/2016
Public Service Co. of OK	AEP	Oklahoma	Ca-PUD201500208	Electric	Vertically Integrated	84.4	10.50	8/31/2016
Duke Energy Progress LLC	DUK	South Carolina	D-2016-227-E	Electric	Vertically Integrated	79.0	10.75	12/15/2016
South Carolina Electric & Gas	SCG	South Carolina	D-2016-224-E	Electric	Limited-Issue Rider	74.2	NA	10/27/2016
Southwestern Public Service Co	XEL	Texas	D-45524	Electric	Vertically Integrated	71.9	10.25	1/31/2017
Dayton Power and Light Co.	AES	Ohio	C-15-1830-EL-AIR	Electric	Distribution	65.8	10.50	9/30/2016
El Paso Electric Co.	EE	Texas	D-44941	Electric	Vertically Integrated	63.3	10.10	7/31/2016
Delmarva Power & Light Co.	EXC	Delaware	D-16-0649	Electric	Distribution	62.8	10.60	5/17/2017
Pacific Gas and Electric Co.	PCG	California	A-15-09-001 (Gas)	Natural Gas	Distribution	62.6	NA	12/31/2016
UGI Utilities Inc.	UGI	Pennsylvania	D-R-2015-2518438	Natural Gas	Distribution	58.6	11.00	10/19/2016
Columbia Gas of Pennsylvania	NI	Pennsylvania	R-2016-2529660	Natural Gas	Distribution	55.3	11.00	12/19/2016

Source: SNL Energy

What are the next key rate case developments?

- **Settlements:** We flag Con Edison and PG&E could see rate case settlements in coming weeks. PG&E has communicated it in discussions already, while ConEd Edison typically attempts to settle their cases during the current period. We believe a potential PG&E deal could help shares continue to re-rate from lower regulatory risk *despite* the pending criminal case.

Appendix:

[Macro-Strategy Key Issue](#) - It's 'Leave' - Implications for UK, Europe & markets

[European Equity Strategy](#) - UK LEAVES: market, sectors & stock impact

[US Equity and Derivatives Strategy](#) - It's 'Leave' – what it means for the US

[US Economic Comment](#) - It's 'Leave' – Brexit Delays Fed Tightening

For more information, see our recent UBS macroeconomic notes:

[6/17/16: 1-family housing pickup likely; multifamily less so](#)

[6/17/16: What to Watch in the Week Ahead](#)

[6/16/16: Is there a preference for pessimism?](#)

[6/16/16: Core CPI up at a 2 ½% annual rate so far this year](#)

[6/15/16: FOMC: Take the summer off, we are.](#)

[6/15/16: Weak IP, but signs of rebound & of pricing power](#)

[6/14/16: Booming consumption despite jobs](#)

Figure 20: Regulated Utilities Comp Sheet

	Price 7/19/2016	Dividend Yield	Short Interest	Days to Cover	P/E Multiple			
					2016E	2017E	2018E	2019E
REGULATED INTEGRATED UTILITIES								
Large Cap	Price	Yield	Short	Days	2016E	2017E	2018E	2019E
Ameren Corp.	52.25	3.25%	2.2%	3.3	21.0	18.7	17.4	16.3
Alliant Energy Corp.	39.46	2.98%	2.9%	1.1	20.8	19.6	18.6	17.8
CenterPoint Energy Inc	23.92	4.31%	3.2%	3.1	20.8	19.7	18.5	17.9
CMS Energy Corporation	44.88	2.76%	3.5%	3.7	22.2	20.8	19.4	18.2
Consolidated Edison	78.90	3.40%	4.0%	4.9	19.8	19.4	18.8	17.8
DTE Energy Co.	97.70	3.15%	1.4%	2.3	19.8	18.3	16.8	15.3
Duke Energy	85.21	4.01%	2.9%	5.6	18.3	17.8	17.0	16.3
Edison International	76.96	2.49%	1.5%	2.7	19.8	18.5	17.7	16.3
Eversource Energy	57.93	3.07%	1.4%	2.4	19.5	18.8	17.8	16.7
PG&E Corporation	64.42	3.04%	0.9%	1.3	17.2	17.7	17.0	16.1
Pinnacle West Capital Co.	79.44	3.15%	3.2%	4.5	19.6	19.0	17.5	17.1
PPL Corporation	37.11	4.10%	1.1%	1.0	15.8	15.2	14.6	14.1
SCANA Corp.	73.63	3.12%	4.1%	4.9	18.6	17.6	16.8	16.2
Southern Company	53.59	4.18%	2.2%	3.1	18.9	18.8	18.0	17.4
WEC Energy Group Inc.	64.03	2.66%	3.2%	4.0	21.8	20.6	19.2	18.2
Xcel Energy Inc.	43.73	3.11%	2.3%	3.2	19.9	19.0	18.2	17.1
Average		3.30%	2.5%	3.2	19.6	18.7	17.7	16.8
Small and Mid-Caps	Price	Yield	Short	Days	2016E	2017E	2018E	2019E
ALLETE	63.55	3.27%	2.1%	3.4	19.9	18.0	17.7	16.5
Avista Corp	43.37	3.16%	3.1%	4.6	21.1	20.4	19.5	18.6
Black Hills Corp	62.02	2.71%	10.0%	13.1	20.6	17.5	16.0	na
El Paso Electric Co.	46.77	2.65%	1.8%	2.2	18.7	17.8	17.0	16.0
Great Plains Energy	30.07	3.49%	3.2%	2.2	17.5	16.6	15.7	15.0
Idacorp, Inc.	80.03	2.55%	2.0%	2.4	20.6	19.9	19.5	na
MGE Energy	56.10	2.10%	2.4%	5.2	24.4	22.9	22.0	21.2
NorthWestern Corp	61.02	3.28%	2.5%	3.5	18.6	17.8	16.6	15.8
Portland General Electric Company	43.92	2.91%	2.7%	4.2	20.0	18.3	16.9	15.9
PNM Resources Inc.	33.99	2.59%	3.6%	4.2	21.3	18.1	16.4	15.8
Spire Inc	68.19	2.87%	4.4%	7.0	20.1	19.3	19.0	17.3
OGE Energy Corp	31.91	3.45%	2.5%	3.7	18.1	16.9	15.7	15.0
Vectren Corp	51.59	3.10%	1.2%	2.2	20.9	19.3	18.3	na
Average		2.93%	3.2%	4.5	20.1	18.7	17.7	16.7
Regulated Average		3.14%	2.8%	3.8	19.9	18.7	17.7	16.8

Source: Company Filings, UBS Estimates, and FactSet. *Unrated companies are FactSet exclusively.

Latest Thoughts on Power Markets

We present below key themes on the power sector heading into 2Q results.

- (1) **Retail debate is back:** We note valuation of retail businesses has once more garnered headlines as the question is *how* to value these businesses for NRG, EXC, and now EFH's competitive segment once more. Companies continue to argue the merits of garnering an equivalent EV/EBITDA multiple on these businesses as their generation as they seem as effectively an extension of their physical generation operations. We continue to take a divergent view here.
 - a. **Not all retail created the same.** We caution investors that the residential retail strategies in Texas pursued by NRG and EFH (TXU Energy) rely on high margins on a relatively smaller set of residential customers. In contrast, EXC's business relies on high volumes at substantially lower margins. We note each of these has their own respective risks, albeit drive the bulk of the consolidated FCF at each one of these Genco entities.
 - b. **Lower generation multiples actually drive compression in valuation spread.** Ascribing 6-7x EV/EBITDA across most generation valuations of late, we note the 5-6x we apply to the retail businesses arguably has eliminated any historic discount already.
 - c. **Keeping assets around to reduce the risk.** We also note in EFH's recent presentation that they appear to emphasize an integrated approach. We caution investors that even assets in Texas with negative FCF appear to be kept open in an effort to hedge their otherwise lucrative retail operations. *The question is just how much of a loss will be tolerated from a generation asset in order to hedge retail risk?*
- (2) **Harvesting cash from legacy assets:** A key theme emerging is reducing the run-rate of maintenance capex in assets to improve FCF of generation businesses. We suspect companies from NRG, to DYN, to FE to focus on improving FCF through reduced capex. We tie future retirements of largely FCF negligible assets to discrete capex decisions.
 - a. **What is the next 'big' capex item?** It's actually a modest investment in a combination of **Coal Ash (CCRs)** and **Effluent Limitation Guidelines (ELGs)** dictating waste water rules on plants. These two have a delayed impact with requirements kicking in 2018+, but should add \$10's of Mns to plant spend (a potentially unpalatable figure in the current environment).
 - b. **Coal is a focus as managing down inventories.** A tangent remains coal pricing and rail rates as companies attempt to bring down their own cost structures. It would appear a modest piece of the overall pressure
- (3) **PJM auction redux: explaining the results and what they mean.** We expect companies to address the implications of the latest PJM capacity auction results from Late May. We note companies such as NRG appear to be poised to talk down future expectations after the auction, particularly around upside prospects for their GenOn portfolio.

- a. **Reducing costs.** We look for FE to reduce its Competitive Business costs yet again as a function of the lower capacity revenues. We note the lower level of investment in assets stands in *contrast* to the higher levels of reliability required under new Capacity Performance (CP) standards.

(4) Foreign investment remains a focal point. We emphasize low interest rates remain a key driver of infrastructure investment across the risk spectrum including in IPP assets. With the downtick in rates of late, we continue to expect new build to stretch into subsequent auctions. We note risk taking for equity returns continues to see a downside bias into the single digits for downside equity cases for new merchant gas projects.

- a. **Expect continued wave of refinancings.** Companies will continue to refi their debt balances, capitalizing on lower interest rates and credit spreads.

(5) Gas Pipeline delays bode well. We note recent delays in multiple pipeline projects as well as clear risks to other ongoing efforts remain a source of upside to power, particularly across the Northeast. Delayed electric transmission assets play a similar role in supporting congestion prices.

(6) La Nina & Weather Trade: Can Summer Heat drive more of a bid in Power? We suspect so, at least via a reduction in coal inventories and pricing. We note a re-emergence in the summer 'weather' trade. In fact, we see many energy investors as narrowly focused on 2017 improvement. In turn, we see this playing out in gas forwards, where 2017 is a 'peak' year at \$3.17/MMBtu of late, backwardated in subsequent years.

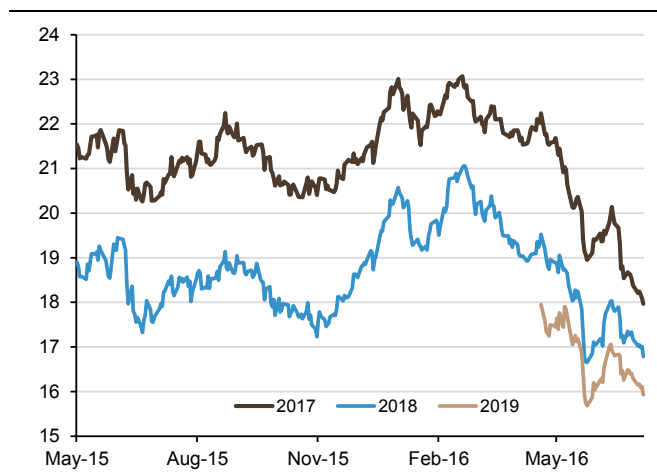
PJM: Investor Denial on Limited Recovery

Following the auction results in May, investors continue to see upside to a PJM recovery next year. While admittedly it should be \$20-30/MW-day under our latest scenarios, we don't see the +\$70/MW-day contemplated by the initial PJM sensitivities disclosed for a prior auction under a 100% Capacity Performance (CP) implementation. We expect companies to gradually moderate expectations through the 2Q reporting season; we also note backwardated PJM sparks are also likely to grab growing attention to this issue.

Capacity is Leading Indicator: New Gen Pushes Down Spark Spreads

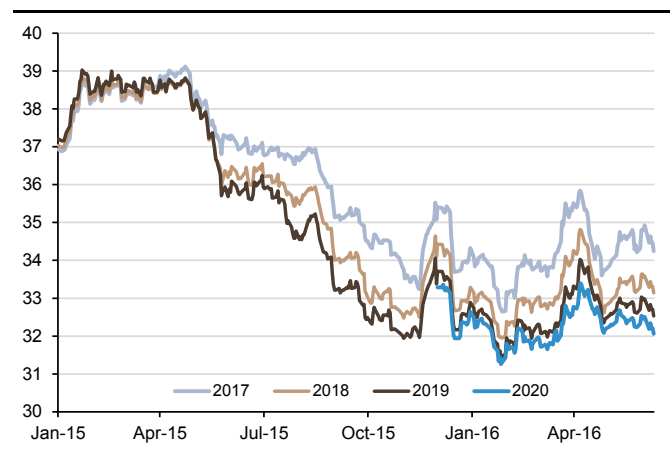
Forward looking expectations continue to decline in PJM amidst concerns over new build in the market. We have been concerned for some time that builds would eventually translate not just into capacity price pressures but into wider Spark spread pressures they begin to reach in-service this year and next in meaningful quantities. We are not surprised to continue to see a meaningful YoY backwardation of forward sparks.

Figure 21: PJM Spark Spreads @ 7.2 HR (\$/MWh)



Source: Platts and UBS estimates

Figure 22: PJM ATC Power Prices (\$/MWh)

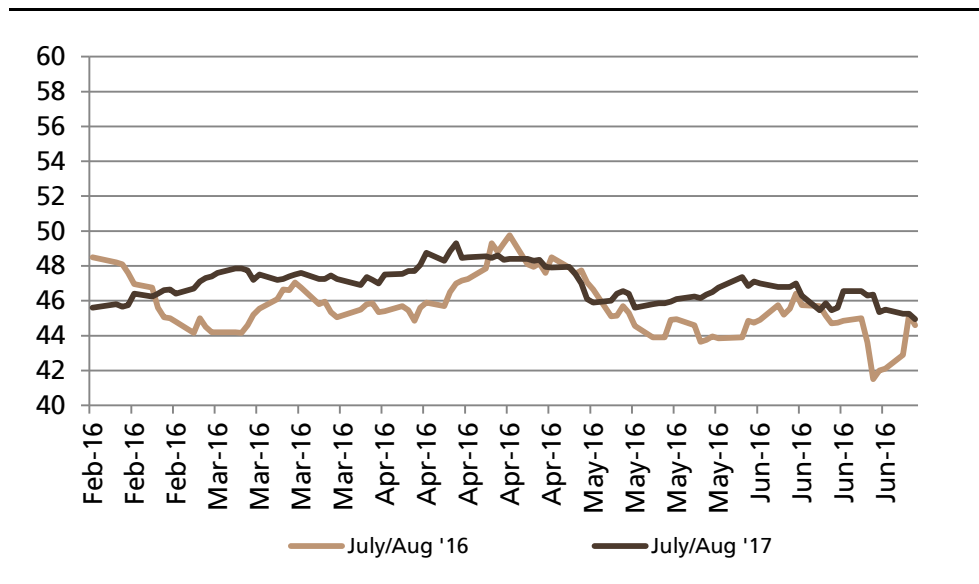


Source: Platts and UBS estimates

Summer forwards are little changed in recent months

Previously 2016 was trading at a premium to 2017 but that dynamic has reversed in February. Overall, summer remains largely unchanged; we expect less volatility under the new Capacity Performance (CP) regime. We note companies appear to be increasingly comfortable with exposure to CP risk despite no risk hours having been incurred yet; the CP program only *began* in May, 2016. We note many continue to work diligently on their compliance strategies which include principally fuel assurance (LDC workarounds and dual-fuel).

Figure 23: Recent PJM Summer Forward Trends: Coming Back a Bit (\$/MWh)



Source: Platts

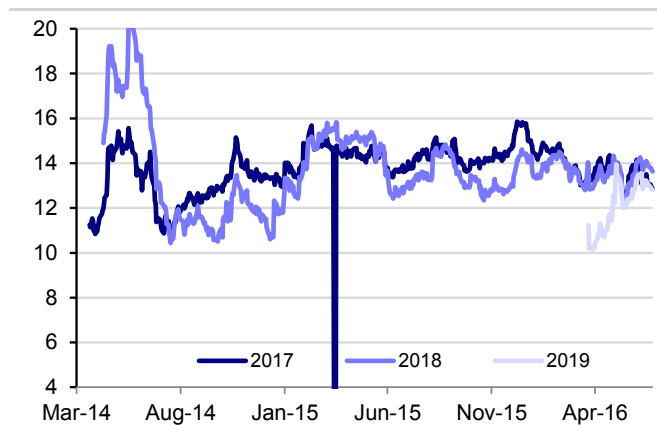
How do NI Hub (Chicago) price trends look? Better.

Although the trend has been overwhelmingly negative we have seen ATC prices stabilize and even recover off their lows. Prices remain below levels needed to support either nuclear generators or new build and the question is whether legislation will be approved to improve the prospects. We emphasize recent closure announcement of Quad Cities is just the first of potentially multiple nuclear plant retirements in the state. We suspect EXC will be diligent in retiring additional assets as the state does not act on their efforts to receive relief for their zero carbon efforts.

Nuclear retirement drive improving prospects

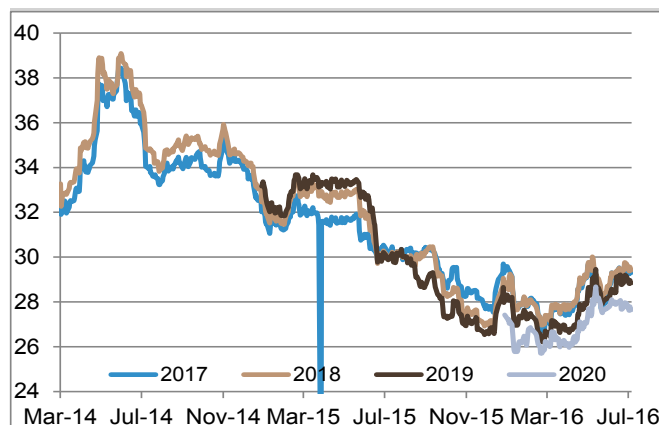
So does rising PRB prices in a marginal coal market.

Figure 24: NI Hub Spark Spreads @ 7.2 HR (\$/MWh)



Source: Platts and UBS estimates

Figure 25: NI Hub ATC Power Prices (\$/MWh)



Source: Platts and UBS estimates

Who's exposed to PJM? Providing the Sensitivities:

Figure 26: Sensitivity - \$1/kW Change in Capacity Pricing - PJM

PJM Capacity Market Upside	TLN	DYN	NRG	EXC	FE	PEG	AEP	CPN	AES	NEE	D	Total
Nameplate Capacity (MW)	11,969	11,940	18,658	22,142	9,477	12,042	8,668	4,946	3,198	1,029	1,408	81,568
EFORd Adj. (MW)	11,271	11,265	17,506	20,794	8,942	11,333	8,135	4,663	2,866	964	1,228	76,430
Clearing Price in 2016/17 \$/MW-Day	\$134.00	\$134.00	\$134.00	\$134.00	\$134.00	\$134.00	\$134.00	\$134.00	\$134.00	\$134.00	\$134.00	
Clearing Price in 2017/18 \$/MW-Day	\$152	\$152	\$152	\$152	\$152	\$152	\$152	\$152	\$152	\$152	\$152	
\$10/MW-day Sensitivity (\$M)	41	41	64	76	33	41	30	17	10	4	4	279
Impact to EPS	\$ 0.21	N/A	N/A	\$ 0.06	\$ 0.05	\$ 0.05	\$ 0.04	N/A	\$ 0.01	\$ 0.01	\$ 0.00	
2017 EPS or EBITDA	\$705	\$1,043	\$2,976	\$ 2.67	\$ 2.36	\$ 2.93	\$ 3.88	\$2,186	\$ 1.25	\$ 6.74	\$ 3.81	
% of total 2017 UBS Estimate	5.8%	3.9%	2.1%	2.1%	2.1%	1.8%	1.0%	0.8%	0.8%	0.1%	0.1%	

Source: Company Filings, PJM, SNL, and UBS

For further background we include links to recent reports below:

[6/29/16: RAAB Roundtable on PJM Market](#)

[6/9/16: Flaring Some Gas in PJM](#)

[5/27/16: Where is it Going & Why The Street is Too ...](#)

[5/27/16: PJM Auction: The Reviews Are In \[Includes ...](#)

[5/26/16: PJM Results Take Two: Who Cleared?](#)

[5/25/16: PJM Results: Generation Gap](#)

[5/23/16: Awaiting the Score for the Annual PJM Auction](#)

[5/20/16: PJM Parameter Update is Slightly Positive](#)

[5/17/16: PJM Capacity Auction Survey: Exhibiting ...](#)

ERCOT: Don't Everyone Move At Once

Waiting for the retirement cycle to start

We emphasize the key story in ERCOT for any real improvement remains an asset rationalization cycle of older, less nimble assets – be it coal or gas. The positive unlevered cash flow, coupled with constructive commentary on asset level profitability alongside prospects for further cuts to fuel, SG&A, and O&M provides less comfort on the margin to the ERCOT recovery. While we still appreciate the ERCOT overall, the ability for the sector to continue to innovate and reduce costs remains an impediment to its own recovery. We emphasize DYN may prove the first to cut its coal plant, but the timeline for others to follow is less clear. We emphasize the Twin Oaks coal plant owned by Blackstone is a lignite coal plant and appears roughly breakeven. Further, the question retirements for EFH appears tied to single capex events as slight or modest FCF losses at each of the more challenged units appears to be palatable amidst ongoing efforts to cut costs and offset retail risk.

Assessing the State of the Texas Power Play – Timeline for retirements is key

We conducted our latest deep-dive into the viability of the state's coal portfolio, seeing nearly all of the state's merchant plants struggling to generate positive FCF in the current power price environment. With at least three waves of environmental regulations potentially impacting the state's portfolio (even prior to the Clean Power Plan), we see limited viability for a bulk of the ~18GW of TX coal (nearly a quarter of the state's 2014A generation portfolio). Of this ~10GWs need to reduce emissions by ~80%+ to comply with the Regional Haze (RH) regulations. With unscrubbed coal plants facing significant compliance costs (potentially hundreds of millions) we believe it is inevitable that several of the states' largest coal assets could opt to retire. That said, the key question remains when they will make a decision. With coal largely uneconomic today we would expect more retirements but generators are ascribing to game theory and are looking to be the 'last man standing' For example, NRG has pointing at other unscrubbed plants that it believes have more significant environmental requirements than its own fleet. For instance, DYN expressed little willingness to maintain the Coletto Creek coal plant given its smaller size (635MW) and potential exposure to future environmental regulations. Facing losses at this coal plant we see DYN as incentivized to shut the asset given its 4GW of other newly acquired ERCOT assets.

But timing is of the essence here – when will coal finally give it up? 2017E.

Based upon conversations with industry experts in Texas air quality regulations and precedent for similar cases we see an increasing potential for a stay in the implementation of the RH regulations. If a stay is granted this could delay the compliance decision for assets to 2017 from 2016 but compliance would still be in the ~2019-2021 timeframe. The bulk of recent appeals to EPA's imposition of Regional Haze regulations have ultimately been upheld by the judicial system but a delay in timing could delay retirement decisions. While plants could well announce further mothballing as soon as this Fall given the current state of the market, formal retirement decisions could well be delayed out a year until firm clarity is received on the RH regulations. Timing of the ongoing EFH bankruptcy could also prove an important indicator of retirement timeline.

Any way the regulations get cut, we see the timeline as pointing to as early as ~2019, but more likely in the 2020-2021 timeframe for Regional Haze.

Will investments be made to retrofit existing scrubbers? We doubt it.

Amidst the particularly high cost of capital implied by current equity valuations, we see limited palatability to investing in negative FCF assets, even if modest retrofits are required given the weak resulting IRRs with upfront negative cash flows.

No one is winning in Texas – except Calpine: Reiterate CPN as IPP top pick

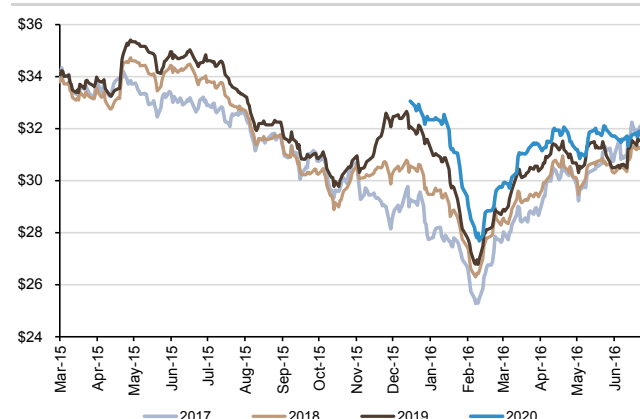
What is increasingly clear is most IPPs are actually losing cash/close to break-even in operating their physical assets (ex-Retail), including NRG, EFH (using their previous disclosures), TLN (gas portfolio), and DYN (Engie). Rather, power hedges and retail enable positive overall cash flows for NRG and EFH. We believe the lone winner who generates meaningful cash flow today from its portfolio is Calpine—and more importantly – the player with staying power given the level of power remains CPN. We see EXC's modest position in the state as also a stable small piece of this story, but largely leveraged via its ExGen Texas financing. We are refining our Texas thesis to reiterate not only our preference for this market, but we see Calpine as uniquely positioned to benefit from this trend given limited compliance capex relative to peers.

Even nukes should be included in this analysis.

Amidst our focus on the portfolios of NRG, we note the nuclear plants merit attention. We believe NRG's two unit site at the South Texas Project (STP) would appear to risk have a negative FCF profile. Based on NEI disclosures the average US nuclear unit had an all-in cost of \$36/MWh in 2014 with first quartile units closer to \$29/MWh. We emphasize NRG's STP Plant is likely a ~breakeven FCF asset, albeit the latest recovery likely puts this back into the green. Comanche Peak at \$26/MWh is clearly well in the money.

Nuclear assets in TX appear to be operating near break-even, or potentially generating losses when including nuclear fuel.

Figure 27: ERCOT-Houston ATC Power Prices(\$/MWh) – meaningfully recovering



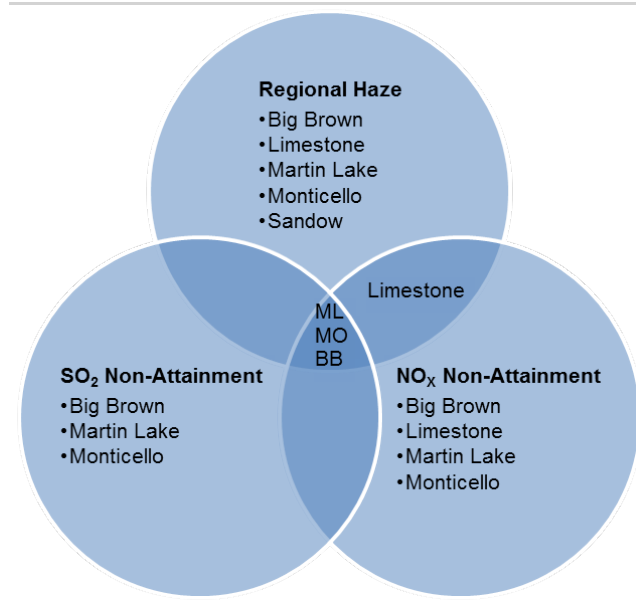
Source: Platts

What are the regs on the table? There are three separate paths.

The primary regulation driving compliance is the recent finalization of the EPA's Regional Haze (RH) regulations on Texas in January (imposed on the state by the EPA using a Federal Implementation Plan, FIP, after rejections of the state's own State Implementation Plan, SIP). We note this regulation would allow for coal plants with existing scrubbers 3-years to retrofit while those without any scrubber retrofits would be afforded a 5-year period to reach compliance, with the clock ticking as of this January (assuming no stay). While Haze regulations in other states have principally targeted NO_x emissions, in this particular instance the regulations are focused on reducing SO₂ emissions – and have specific targets. This is the most encompassing of the three standards with respect to plants impacted.

In addition we highlight that there are additional local rules which could further pressure plants including Monticello, Martin Lake, and Big Brown

Figure 28: Texas Environmental Regulations



Source: EPA, SNL Energy, Sierra Club, and UBS Estimates, Company Filings

Renewables threaten the recovery

We see the declining cost of utility-scale solar as among the greatest risks to the timeline in the recovery in this market. Just as soon as the outlook for coal retirements and limited new gas could look bright in 2017, we expect to see more 'merchant' solar (10-year financial swap deals) in the 2018 or 2019 timeframe in this lower-cost market. We estimate high \$30/MWh peak prices appear to potentially support entry of projects (a level off which forwards are currently not far off). We believe all-in pricing could trend to shy of \$1/W by later in the decade (ex-margin), suggesting all-in projects could be sold in the \$1.20-1.30/W ballpark. Recall FSLR was the first to development merchant solar in the state, with its more 'experimental' investments at the Barilla plant (30MWs).

Where are ERCOT power prices capped? At the cost of entry for new renewables.

More structurally, we perceive growing fears over concerns that Texas power prices have a de-facto cap tied to the price at which renewables can 'enter' the market. We see this as limiting improvement prospects for both off- and on-peak prices. While gas plant additions remain a relevant factor with a litany of sites under development already, some of which have contracts already in hand, including Brownsville, with 200MWs of contracted output to the local utility.

No more transmission for now.

We note limited incremental new transmission plans for either the Panhandle region (PREZ) or West Texas (for contemplated solar build) to accommodate the continued build of renewables. Following the success of the original CREZ transmission lines (with almost all of its contemplated 18GW of capacity used by incremental renewables since its construction), the question has been whether the state would pursue any further large-scale efforts. While in Texas much of the expansion costs for generators is paid for by the utility, we note the limit on transmission capacity would appear to place a cap on development across this

But when will the renewables hit (again)?

Is it wind or solar? Unclear, but both pose a potential risk.

This price is entry is declining

Once CREZ is full don't look for another set of projects yet

portion of the state, with a focus for new wind turning towards ERCOT-South particularly given its more on-peak orientation.

But wait, where could we see more transmission? Around retirements.

We also met with CNP management in Houston who described potential future transmission investments to backstop potential coal and steam-based gas plant retirements in the state. For instance we note NRG recently mothballed indefinitely another gas-based steamer unit in the region, a leading indicator towards a permanent retirement.

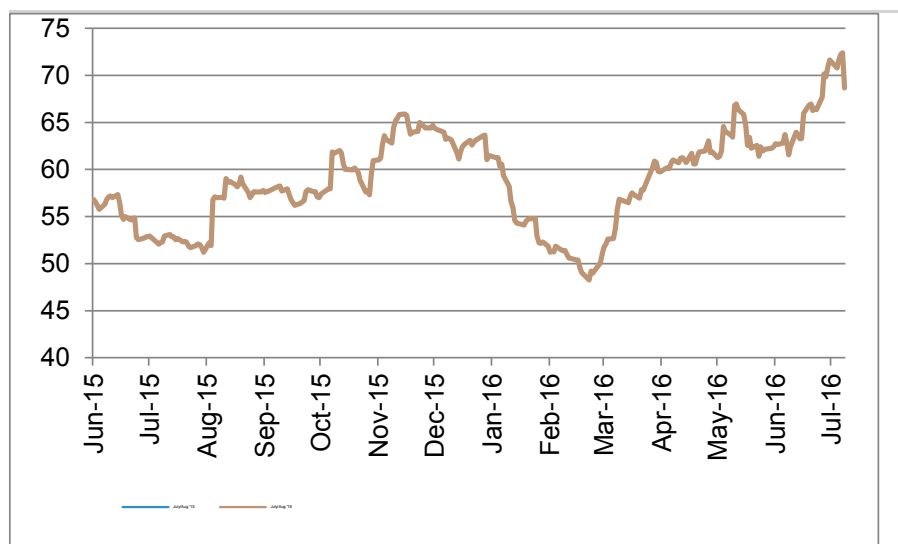
Summer-Time Concerns: Getting a bit Windy of Late?

Among the other growing themes in the market is the penetration of wind. We note recent above-average wind dispatch further calls into question expectations for the total potential wind dispatch into the market at seasonally peak periods, likely weighing on Summer peak price expectations (July/Aug). We emphasize last week wind in Texas claimed a new high water mark for mid-summer dispatch at ~23% of total market share during the hotter ERCOT day – this translates to a roughly ~low 70% capacity factor on the existing wind fleet during a heat wave (despite coincident historic peak expectations for wind during on-peak periods in the ~20% range).

Of late, the summer forwards have recovered to a multi-year high as the split between peak and off-peak has reached new disparities. The question is whether expectations for above-average weather and limited impact from renewables (wind) during peak times will enable this price formation. Overall, recent price trends of late remain quite supportive.

Challenging the assertion that wind doesn't blow during the summer in Texas

Figure 29: Summer July/Aug 2017 Curve for ERCOT Houston



Source: Platts

PUCT Looking at Retail Again

On June 9th the Public Utilities Commission of Texas (PUCT) announced that it will be reviewing the practices of competitive electric retail providers in the state. A special meeting on June 21st will be held with stakeholders and hosted by Chairman Donna Nelson to help make the shopping process easier for consumers but addressing what have been perceived as confusing offers. In Texas most

Reforms which increase the rate of customer switching could negatively impact players with large market share such as NRG

customers can shop for their retail electric provider on www.powertochoose.org. Some of the incumbent retail providers have proposed closing the PUCT-managed website in favor of individually selling plans to consumers but the PUCT would prefer to maintain the independent site. Commissioner Ken Anderson commented that retail providers could face sanctions and enforcement actions for failure to comply with the rules.

On June 11th there were 312 offers on PowertoChoose which ranged from 1¢/kWh to 13.5¢/kWh with companies including GexaEnergy, InfiniteEnergy, and Reliant (NRG Energy) offering 3¢/kWh or lower advertised rates. The rates are based on 1,000kWh monthly usage and have significantly higher costs per kWh at different volumes due to bill credits at 1,000kWh per month. For example, in Reliant's "Bulls-Eye 3" plan there is a credit for usage between 1,000-2000kWh per month which we detail below ([Further details are available here](#)). Per the EIA the average monthly consumption in Texas was 1,158kWh at an average price of 11.86¢/kWh in 2014. Although the average consumption is above the 1,000kWh level, this is likely skewed by the peak summer months.

Bill credits for narrow usage windows, high termination fees, and other bill terms make it challenging for customers to accurately shop for electricity.

Figure 30: Reliant Bull's-Eye 3 Plan Scenario Analysis

Reliant Bull's-Eye 3 Plan Scenario Analysis					
Usage (kWh)	500	Usage	1,000	Usage	2,000
Base Charge (\$)	\$0.00	Base Charge	\$0.00	Base Charge	\$0.00
Energy Charge (\$/kWh)	\$0.034	Energy Charge	\$0.034	Energy Charge	\$0.034
Credit (\$)	-\$40.00	Credit	-\$40.00	Credit	-\$40.00
Delivery Charge (\$/kWh)	\$5.25	Delivery Charge	\$5.25	Delivery Charge	\$5.25
Energy Delivery (\$/kWh)	\$0.0307	Energy Delivery	\$0.0307	Energy Delivery	\$0.0307
Monthly Fixed (\$)	\$5.25	Monthly Fixed	\$5.25	Monthly Fixed	\$5.25
Monthly Variable (\$)	\$32.34	Monthly Variable	\$64.67	Monthly Variable	\$129.35
Monthly Credit (\$)	\$0.00	Monthly Credit	-\$40.00	Monthly Credit	\$0.00
Total Cost (\$)	\$37.59	Total Cost	\$29.92	Total Cost	\$134.60
All-In Cost per kWh	\$0.075	All-In Cost per kWh	\$0.030	All-In Cost per kWh	\$0.067

Source: PowertoChoose

Why does this matter? NRG Energy and Energy Future Holdings (EFH) are both leaders in the Texas retail market and any reforms which encourage customer switching could reduce cash flows going forward. Retail operations represent 30% of NRG's EBITDA ex-NYLD and a disproportionate amount of their free cash flows.

Debate is refocusing on the retail – is this keeping generation open? We emphasize given the robust margins earned by this business for incumbents, the question is whether this is acting as a barrier to closing plants that are otherwise garnering negative EBITDA and FCF. With multiple companies emphasizing the integrated nature of the platform (and hence integrated nature of the profitability seemingly), we would suspect that this is the primary culprit behind the paucity of generation retirements thus far in Texas.

[Further details are available at Ofgem's switching program site here.](#)

[Additionally, the latest on Ofgem and the CMA's competition assessment are here.](#)

ERCOT: For further background we include links to recent reports below:

[ERCOT: Ever More Hazed and Confused](#)

[Riding the Commodity Bull in Texas](#)

[ERCOT: A Solar Eclipse?](#)

[Merchant Solar Arrives in Texas](#)

[Taxless Tieups in Texas](#)

[Reading the Tea Leaves in Texas Transmission](#)

[Putting a Texan Spin on the Power Outlook](#)

[Texas: Hazed and Confused](#) [Regional Haze regulations]

Figure 31: May CDR Report -> Looking at High Reserve Margins

CDR Update w/ UBS Adjustments	2017	2018	2019	2020	2021
Load Forecast:					
Total Summer Peak Demand (based on normal weather)	71,416	72,277	73,663	74,288	74,966
less: LRs Serving as Responsive Reserve	1,153	1,153	1,153	1,153	1,153
less: LRs Serving as Non-Spinning Reserve	0	0	0	0	0
less: Emergency Response Service (10- and 30-min ramp products)	1507	1507	1,507	1,507	1,507
less: TDSP Standard Offer Load Management Programs	208	208	208	208	208
Firm Load Forecast, MW	68,548	69,409	70,795	71,420	72,098
Prior Load Forecast	68,341	69,276	70,329	71,254	72,180
Change vs., Prior	0.3%	0.2%	0.7%	0.2%	-0.1%
Nominal Growth in Load YoY (MW)	485	861	1,386	625	678
Y/Y %	0.7%	1.3%	2.0%	0.9%	0.9%
5-year CAGR					1.2%
Operational Generation, MW					
Installed Capacity, Thermal/Hydro	65,990	66,165	65,325	65,325	65,325
Capacity from Private Use Networks	4,292	4,540	4,536	4,465	4,436
Non-Coastal Wind, Peak Average Capacity Contribution (12%)	1,693	1,693	1,693	1,693	1,693
Coastal Wind, Peak Average Capacity Contribution (55%)	1,015	1,015	1,015	1,015	1,015
RMR Capacity to be under Contract	0	0	0	0	0
Capacity Contribution - Non-Synchronous Ties, MW	577	577	577	577	577
Switchable Capacity, MW	2,972	2,972	2,972	2,972	2,972
Available Mothballed Capacity, MW	805	805	805	805	805
Solar Utility-Scale, Peak Average Capacity Contribution (80%)	230	230	230	230	230
Planned Resources (not wind) with Signed IA, Air Permits and Water Rights, MW	1,400	6,207	7,185	7,425	7,425
Planned Non-Coastal Wind with Signed IA, Peak Average Capacity Contribution (12%)	838	1,083	1,167	1,167	1,167
Planned Coastal Wind with Signed IA, Peak Average Capacity Contribution (55%)	305	619	619	619	619
Planned Solar Utility-Scale, Peak Average Capacity Contribution (80%)	1,177	1,412	1,412	1,412	1,412
Total Resources, MW	81,295	87,319	87,538	87,707	87,678
less: Switchable Capacity Unavailable to ERCOT, MW	-300	-300	-300	-300	0
less Retiring Units, MW	0	0	0	0	0
Resources, MW	80,995	87,019	87,238	87,407	87,678
Ex-new units (Cumulative)	2,320	3,115	3,199	3,199	3,199
Total Resources, ex-new units	78,675	83,905	84,039	84,208	84,479
Reserve Margin (Official May 2016 CDR)	18.2%	25.4%	23.2%	22.4%	21.8%
Previous forecast (May 2015 CDR update)	18.5%	21.4%	18.7%	17.1%	16.1%

Source: ERCOT and UBS estimates

MISO: Riding the Roller Coaster

Looking at the latest on Capacity Reform

With the long-debated process reaching some conclusion, we note a continued open division between the Market Monitor and MISO on the 'right' approach for its new capacity construct. We note competing constructs are focused on:

- (1) Whether to pursue a forward (3-yr) vs. prompt year procurement?
- (2) Who is eligible to participate (all supply or just competitive?)
- (3) What demand would be served? Just competitive zones or all legacy?
- (4) What kind of demand curve? Sloped , extended slope or otherwise

We note an ongoing focus on mitigating price volatility for merchant generators as well as demand.

What's the timeline from here?

- July 14: Brattle Presentation
- July 20: Tariff Language and Business rules Posted
- August 3/4: RASC Meeting
- August 8: Markets Committee of the Board

Retirements still coming for both DYN and EXC: not high enough

Although the latest capacity auction surpassed our estimates (to the upside), the ~50% decline versus the prior year will still significantly pressure merchant generators in the Illinois region.

Further details about potential retirements are available in the Dynegy and Exelon sections of the note below.

Figure 32: MISO Capacity Auction Snapshot

MISO Local Resource Zone	Zone 1 MN, ND, Western WI	Zone 2 Eastern WI, Upper MI	Zone 3 IA	Zone 4 IL	Zone 5 MO	Zone 6 IN, KY	Zone 7 MI	Zone 8 AR	Zone 9 LA, TX	Zone 10 MS
Region										
2014-2015 ACP (\$/MW-d)	\$3.29	\$16.75	\$16.75	\$16.75	\$16.75	\$16.75	\$16.75	\$16.44	\$16.44	N/A
2015-2016 ACP (\$/MW-d)	\$3.48	\$3.48	\$3.48	\$150.00	\$3.48	\$3.48	\$3.48	\$3.29	\$3.29	N/A
2016-2017 ACP (\$/MW-d)	\$19.72	\$72.00	\$72.00	\$72.00	\$72.00	\$72.00	\$72.00	\$2.99	\$2.99	\$2.99
2016-2017 ZRC Offer Cleared	4,522	2,840	9,636	8,242	7,927	14,060	20,141	9,676	17,934	4,511
2016-2017 Total Committed	18,775	14,903	10,138	9,152	7,927	18,398	21,534	9,995	18,511	6,151
2016-2017 FRAP (Delta)	(14,253)	(12,063)	(502)	(910)	-	(4,338)	(1,393)	(319)	(577)	(1,640)
2016-2017 Conduct Threshold	\$25.80	\$26.06	\$25.52	\$25.93	\$26.42	\$25.85	\$25.98	\$24.76	\$25.12	\$24.61
2016-2017 CONE	\$258.00	\$260.58	\$255.15	\$259.26	\$264.19	\$258.47	\$259.81	\$247.56	\$251.21	\$246.05

Source: MISO | ACP = Auction Clearing Price; ZRC = Zonal Resource Credits; FRAP = Fixed Resource Adequacy Plan; CONE = Cost of New Entry

What will Dynegy do? We note the move to retire individual units at both Newton and Baldwin was unusual in our view, where coal generators have historically opted to keep more economic units intact, shutting smaller less profitable units altogether. *We would not doubt further retirements if the ongoing reforms prove insufficient.*

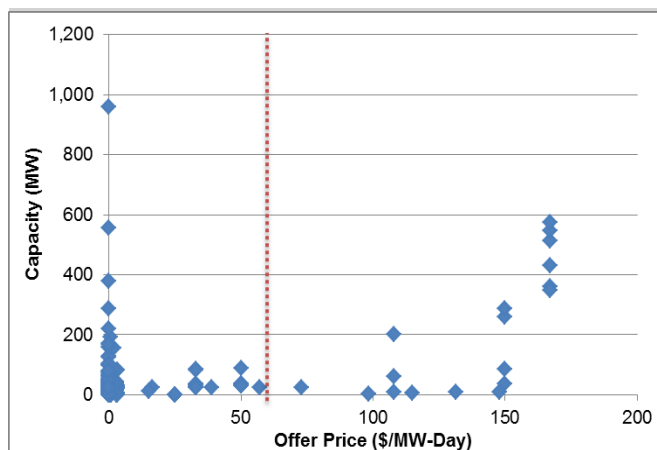
Distilling Last Year's Supply Curve for Clues on Clinton Retirement

Below we show the offer price (\$/MW-day) relative to segment offer capacity (MW) for the 2015-2016 MISO auction showing where individual units bid in the previous auction. We have imposed the \$72/MW-day clearing price for both zones 4 and 7 over the data to show which units that cleared in the previous auction would not have cleared in the 2016-2017 auction assuming the same bidding behavior.

In the 2015-2016 auction for Zone 4 there were four market participants who bid over \$33/MW-day with average offer prices of \$144 (2,560MW), \$159 (1,151MW), \$87 (126MW), and \$40 (695MW). The market participant who bid 1,151MW at \$159/MW-day also interestingly bid \$0/MW-day for a separate 1,709MW which included one 958MW plant (the top left datapoint in the IL figure below).

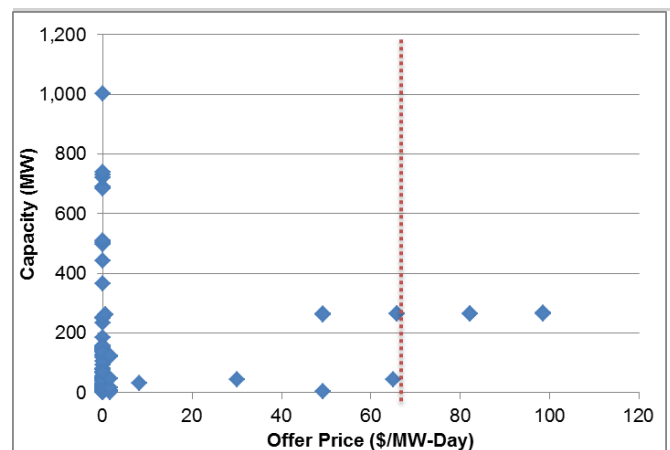
Exelon commented last auction that it has historically bid in its 1,069MW Clinton nuclear plant as a price taker and in the 2015-2016 auction it did execute bilateral contracts reducing the amount of capacity available to bid. Leveraging the below chart we see prices recovering to the ~\$150/MW-day level, albeit we would expect the bidding behaviors to shift such that the full price may not be realized (DYN would bid more into this auction).

Figure 33: IL Zone 4 2015-2016 Bidding Data



Source: MISO

Figure 34: MI Zone 7 2015-2016 Bidding Data



Source: MISO

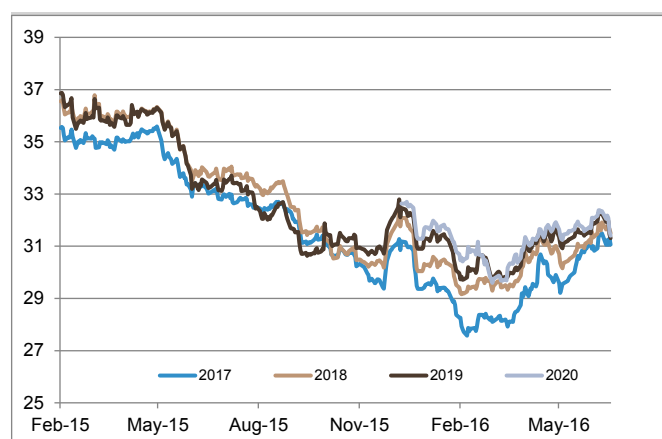
In Michigan there was one asset owner who bid in 2,644MW for 2015-2016 at prices ranging from \$1/MW-day to \$99/MW-day and only cleared 525MW at \$3.48/MW-day; this was one of the few market participants to not bid in \$0/MW-day. For example one market participant bid 10,953MW at \$0/MW-day, presumably a regulated entity. *For more supply curve information please see [here](#).*

What's the looming risk? Transmission.

While the near-year improvements should provide some resiliency, we caution that forward procurements (3-year as contemplated under the MISO reforms) would bring the ongoing Ameren transmission upgrades to within the timeframe of the forward auction. As such, we see clear risk to the downside. Once more, we reiterate the exact definitions of *which* supply is able to participate will be critical as Zone 4 becomes largely de-constrained and part of the wider MISO North zone.

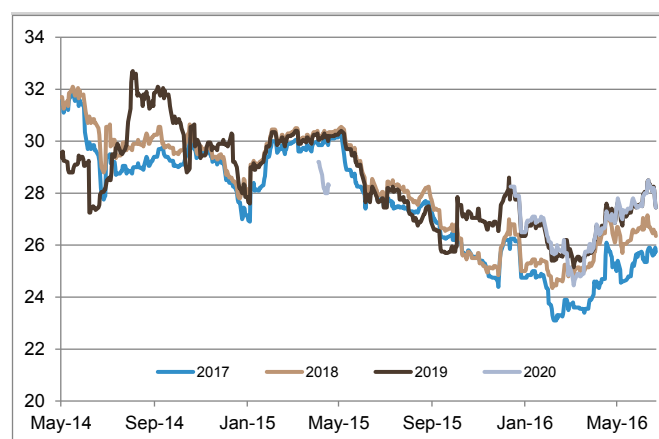
What can the 2015-2016 MISO auction teach us about the current 2016-2017 auction?

Figure 35: Indy Hub ATC Power Prices (\$/MWh)



Source: Platts

Figure 36: Indy Hub Offpeak Power Prices (\$/MWh)



Source: Platts

For further background we include links to recent reports below:

- [6/16/16: DYN: Simplifying the Art of the Deal](#)
- [6/9/16: DYN: Commodity Rally Priced In: Downgrade to Neutral](#)
- [5/4/16: Taking a Seat at the Negotiating Table](#)
- [4/15/16 Riding the MISO Roller Coaster](#)
- [4/13/16 A Chilly Reality for MISO Auction](#)
- [3/21/16 MISO Moderation](#)
- [1/6/16 MISO: Served Scrambled](#)
- [12/23/15 MISO Transmission Wins Round One](#)

Figure 37: Sensitivity - \$1/kW Change in Capacity Pricing - MISO

MISO Capacity Market Upside	DYN	NRG	NEE	CMS	ETR	EXC	D	CPN	Total
Nameplate Capacity (MW)	5,871	4,733	4,134	1,087	1,075	1,533	77	1,063	19,572
EFORd Adj. (MW)	5,539	4,235	2,006	1,025	984	1,099	8	1,003	15,899
Clearing Price in 2015/16 \$/MW-Day	\$ 150.00	\$ 3.29	\$ 3.29	\$ 3.48	\$ 3.29	\$ 150.00	\$ 3.48	\$ 3.48	
Clearing Price in 2016/17 \$/MW-Day	\$ 72.00	\$ 2.99	\$ 2.99	\$ 72.00	\$ 2.99	\$ 72.00	\$ 72.00	\$ 19.72	
YoY \$/MW-day Sensitivity (\$M)	(158)	(0)	(0)	26	(0)	(31)	0	6	(158)
Impact to EPS			(\$ 0.00)	0.06	(\$ 0.00)	(\$ 0.02)	\$ 0.00		
2018 EPS or EBITDA	\$ 1119	\$ 3113	\$ 6.32	\$ 2.02	\$ 4.86	\$ 2.57	\$ 3.79	\$ 1915	
% of total 2017 UBS Estimate	-14.1%	0.0%	0.0%	3.0%	0.0%	-0.9%	0.0%	0.3%	

Source: Company Filings, PJM, SNL, and UBSe

New England: Running on Empty?

Risk of gas pipeline rejection bodes well for regional power prices

We see some near-term relief potentially from a clear risk for a gas pipeline to be rejected by the Mass SJC, which could effectively end for the time being gas pipeline expansions into the region as we would expect neighboring states to abandon their efforts.

The Massachusetts legislation – really about Hydro

Following the reintroduction of Senate Bill 1965, feedback from industry checks indicates a strong possibility for legislation in MA this Summer that will include upwards of ~18TWh of contracting under an expanded Clean Energy RFP seeking low carbon resources to meet the states' Global Warming Solutions Act targets, given the need to address solar caps in the state. In our recent meeting with Avangrid (AGR), management framed the prospects for this legislation as really about hydro, more so than the ongoing RFP across the three-states, which would appear focused on more conventional resources. We believe this would explain ES' decision to pursue the New York export project into New England. AGR appears keen to compete with ES on the export avenue with its own Canadian interconnection itself. While a modest investment to interconnect its Northern Maine wind projects into Canada, this remains pending an RFP to do so from New England to pursue the project. Expect this to become a more fully defined procurement project in the coming months.

Watch for efforts on an omnibus energy bill following the recent successful passage of a solar net metering cap increase. We understand this remains a top priority of Governor Baker to pass a bill that would call for the procurement of large-scale hydro and offshore wind.

Irrespective, into the June expiration of the session this remains a unique risk for IPPs, and a key potential positive for ES

Selections could be coming soon in Three-State Clean Energy RFP

Proposals were submitted on Jan 28, however, we worry the solicitation could come later than its late July timeline (late summer?). The RFP is a joint proposal from MA, CT, and RI for 5TWhs of carbon-free renewables and hydroelectric energy, with winning contracts submitted for regulatory approvals, expected in 'Summer'. ES is participating with both the Northern Pass and [Clean Energy Connect](#) projects. We see this as a smaller procurement effort ahead of a potentially larger effort next year.

Where will spark spreads trend? Cheap gas offset by even cheaper renewables

We believe new build plants in the region will continue to rely upon cheap- and declining delivered natural gas prices to the region to drive the equity returns on new investments in plant. The question remains whether sparks will improve at all given the vast majority of dispatch remains gas-driven (we believe yes still); however, the risk to the expanding spark story is the timeline for new renewable resources, pushing down LMPs. We see high regional RPS standards as fundamentally requiring high capacity to offset weaker regional energy margins. We also note that the new build costs and brownfield economics appear quite competitive – with Invenergy touting ~\$900/kW in some of its disclosures (a near record low for a CCGT in ISO-NE).

What are Key Elements of the Mass Legislation?

The bulk of the provisions are indeed constructive with a clear push for additional renewables, leaving ample procurement latitude for Northern Pass. We emphasize the Senate version authorizes the full 18TWh originally contemplated under the

first version of the bill, while the House version contemplates half ~9TWh. Both contemplate an incremental ~1.2GW of offshore wind.

We continue to expect the house and Senate to reconcile their respective bills in time for the July 31st clock. The harder climb has been achieved of passing legislation, and with Governor Baker firmly behind the effort still.

The Massachusetts legislation – running out of time

MA legislature has until July 31st, the end of this legislature period, to decide on the future role of renewables in their state as well as potentially parts of the entire Northeast. So far, both MA House and Senate have passed a renewable bill, H-4385 and S-2372 respectively, which could transform MA into a frontrunner in renewables integration. However, the gap between House and Senate bill is significant – and substantial compromises are necessary from the working group. A deal would then need to be re-ratified by each respective side by end of day on July 31.

The House bill, approved 154-1, plans for 1.2 GW of Canadian hydro and 1.2 GW of offshore wind with utility remuneration of a 2.75% rate of return attached to the legislation. Meanwhile, the Senate bill, passed unanimously, includes 2 GW of offshore wind and a provision for long-term clean energy contracts amounting to no more than 12,450,000 MWh. Moreover, the Senate bill includes a provision prohibiting electric utilities from passing along cost associated to gas projects, ie Access Northeast.

Given the differences between House and Senate bills, we expect a rather senior group of conferees to execute the negotiation process and develop the amended bill to be approved by both chambers and then ratified by the Governor. However, given that the conferees have yet to be appointed and that the national political conventions, RNC on July 17-20 and the DNC on July 24-27, are about to occur, we expect the conferee group to experience some time pressure during their process, which we repeat has a hard stop on July 31st.

While the offshore wind provisions were among the later items added to the bill in both chambers, we do not expect conferees to remove it from the final bill. In Sept 2015, offshore wind experienced a successful session in front of both chambers, arguing that they were not another Cape Wind and that costs reduction make offshore wind very attractive moving into the future. Instead, we expect the senate provision which requires home energy audits on all house sales as well as potentially the 2.75% rate of return to disappear before the final version.

Feedback from industry checks indicates a strong expectation for the renewables legislation to pass. This could include upwards of ~1GW dedicated to hydro resources under some scenarios, a key upside to ES' efforts to execute on transmission imports from Canada. However, the legislative decision to bar electric utilities from doing gas deals could have significant negative impacts on Access Northeast prospects.

Mass bill could open the door to formal contracting for long-distance transmission from Canada

Seeing near-term recovery in gas price expectations

We suspect gas prices could continue to improve not just from the wider improvement in Henry Hub but also from the latest

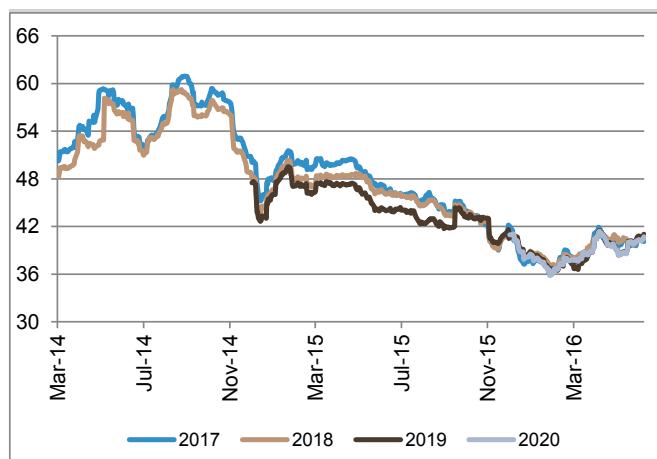
We see this accruing to Dominion: the key wildcard to the upside.

With the among most exposure- and certainly the greatest scrutiny to the New England energy market right now with its ~0% hedged on 2017 for Millstone, we see recovery in 2H16 in gas price (and power price) expectations for its nuclear plant as a key consideration. We see this as among the biggest positive wildcards in the near-term to stabilize EPS.

Another bite at the apple on the CT nuclear legislation?

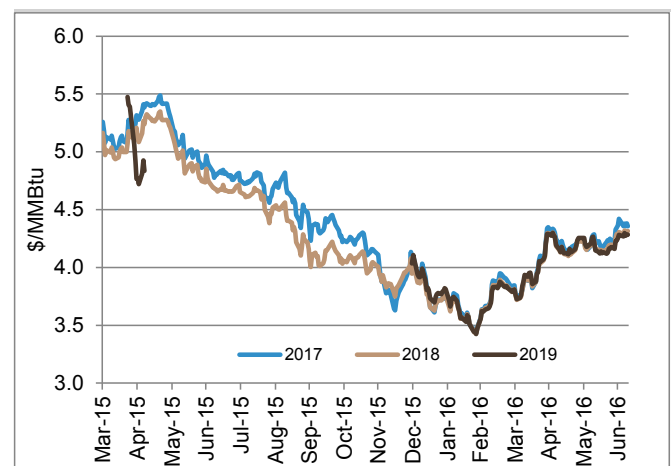
Further, we look for D to pursue another hard effort to get a program in place to effectively contract for a portion if not all of the Millstone unit. We emphasize our initial cut had estimated this as being worth ~\$0.15-0.20 EPS, however would be tied to just how competitive an offer it would need to sell into a new state-specific zero-carbon procurement (vs. other renewables), likely in the \$60's/MWh or lower. See more: [Giving New Life in New England](#).

Figure 38: Mass Hub ATC Pricing (\$/MWh)



Source: Platts

Figure 39: Algonquin Gas (\$/MMBtu)



Source: Platts

Transmission imports – new lines are the wild card for future

The ISO has largely maxed out existing import capability from New York in each of its auction (with the exception of the Crosstown Cable, where Long Island is probably less likely to export to NE given historically NE has exported to them) – thus there weren't major changes to this times auction results on this front. The real wild card here are potential new transmission lines to import more resources into New England, and if one of those gets built, certainly that will change things a lot in terms of capacity imports. We note that there are indeed a number of different proposals for transmission capacity into the region through various RFPs; which could potentially be deemed capacity resources in subsequent periods. ISO NE confirmed on the call that there are rules in place that would allow a new transmission project to come in and qualify its capacity if it met certain criteria – but there are no cases yet qualified.

What about capacity prices? Expect downward pressure next auction

We continue to expect prices to be modestly down YoY given the litany of changes including in the demand curve design. We see pressure for prices to be in a range of ~\$5.50-7.00/kW-mo. Still quite healthy vs adjacent regions, but declining off recent year highs. We suspect new-year EV/EBITDA multiples for IPPs will require all the more attention given the likely backwardated view on both capacity and power spark spreads (we focus our SOP on peak-ish 2018E EBITDA at present for instance, potentially contributing to caution on ascribing historic multiples across the sector of late).

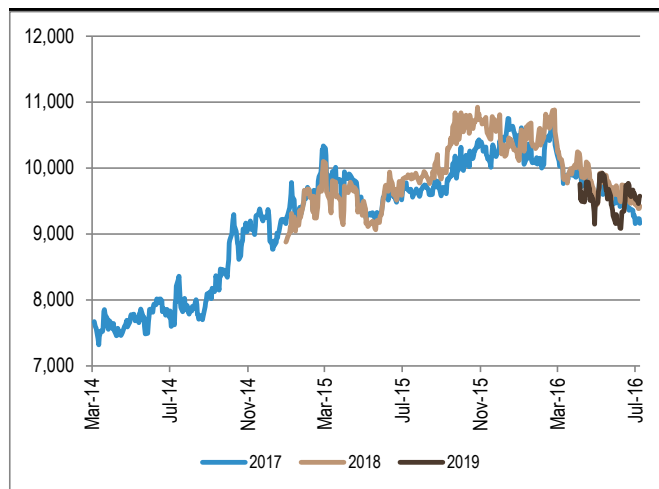
New Hampshire: divestments will likely drive retirements

...Just not there year. We emphasize the 439MW recently scrubbed coal plant Merrimack is quite likely to retire in Bow, NH upon divestment. In fact, it is not clear the plant will be 'divestable' in the process (the current deal with regulators actually addresses this pre-emptively). From a timing perspective, we would not expect a decision to tire *this auction* as the auction of the assets will have yet to take place (and hence don't want to assume no buyers/continued operations). We emphasize this is a clear retirement risk for the subsequent auction in ~2021/2022. We note elevated gas prices once more could yet breath new life into the asset and don't want to assume this shutdown as a forgone conclusion.

Focus from corporates remains on New England

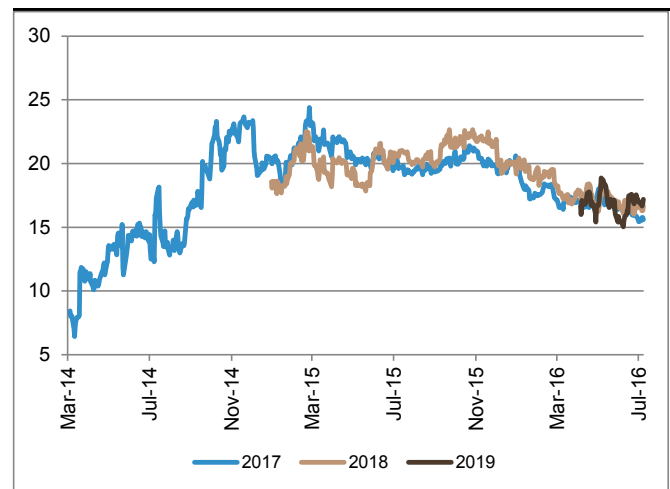
We see a relatively stable outlook for spark spreads in the high teens under the current outlook. We would expect the outlook to become increasingly backwardated as the timeline for new renewables reaching in-service out of both the smaller tri-state RFP and the subsequent likely MA RFP become clearer. It would appear to be more in the ~2019/2020 period.

Figure 40: Mass Hub Heat Rates (btu/KWh)



Source: Platts

Figure 41: Mass Hub Spark Spreads @ 7.2 (\$/Mwh)



Source: Platts

For further background we include links to recent reports below:

[5/11/16 ES: Just Passing Through, with Added Urgency](#)

[3/30/16: Dousing the New England Grid](#)

[2/18/16: What's New in New England? Learnings on the ...](#)

[2/12/16: Read All About It: Why The New England Print ...](#)

[2/11/16: Pouring Cold Water on New England Power](#)

[2/8/216: Adding to New England Import Prospects](#)

[UBS: Pouring Cold Water on New England Power](#)

[How Green Can New England Get?](#)

Please see below for the auction results:

[ISO-NE Forward Capacity Market 10 Results Report](#)

[ISO-NE State of the Grid 2016 January 2016 Presentation](#)

Figure 42: Sensitivity - \$1/kW Change in Capacity Pricing – ISO-NE

NE ISO Capacity Market Upside	CPN	DYN	D	EXC	NEE	NRG	PEG
Nameplate Capacity (MW)	2,193	2,435	2,576	2,777	2,042	2,988	1,161
EFORd Adj. (MW)	2,083	2,252	2,447	2,568	1,888	2,764	1,073
\$1/kw-mo Sensitivity (\$M)	25.0	27.0	29.4	30.8	22.7	33.2	12.9
Impact to EPS			0.03	0.02	0.03		0.02
2017 EPS or EBITDA	2,110	1,216	4.17	2.76	6.38	3,007	2.88
% of total 2017 Estimate	1.2%	2.2%	0.8%	0.8%	0.5%	1.1%	0.6%

Source: Company Filings, PJM, SNL, and UBS

New York: Limiting the Carbon

We are increasingly concerned on prospects for this market

We see risk for power prices and capacity prices to see negative revisions as the NY PSC finalize their proposal for a Zero Emission Credit (ZEC) market by ~Aug 1st. We would expect a negative impact to both power prices (which had seemingly been volatile around these prices points previously) as well as negative to RGGI price expectations (which are currently under a model reset). RGGI implications include potential for other states to follow suit weighing on prices.

We also see NYISO Rest of State Capacity prices remaining relatively flat into 2017 now, see a ~\$5/kW-mo outlook as more reasonably rather than the ~\$8/kW-mo previously estimated. Further, without upside of future nuclear retirements this market is meaningfully less interesting, particularly when coupled with pending RPS implementation. This is most negative to **NRG** followed by **DYN**. This likely brings down the sale price expectation for Independence, pending a sale in the near term.

Figure 43: NYISO Capacity by Operator

NY Capacity (MW)	NRG	ETR	EXC	PEG	DYN	CPN	TLN
Rest of State	1,628	852	1,128	774	1,108	-	1,080
Lower Hudson Valley	758	2,069	-	-	-	-	-
New York City	1,366	-	-	-	-	121	-
Long Island	-	-	-	-	-	231	-
Total	3,752	2,921	1,128	774	1,108	352	1,080
Sensitivity to \$1/kW-Month Change in Capacity Pricing							
Rest of State	20	10	14	9	13	-	13
Lower Hudson Valley	9	25	-	-	-	-	-
New York City	16	-	-	-	-	1	-
Long Island	-	-	-	-	-	3	-
Total	45	35	14	9	13	4	13
2017 UBSe EBITDA	2,944	3,999	6,486	4,481	1,162	2,163	708
% Change	1.5%	0.9%	0.2%	0.2%	1.1%	0.2%	1.8%

Source: SNL and UBS estimates

Expect more transmission interconnection efforts for downstate NY

We emphasize efforts to bring more capacity downstate will continue as entities such as Avangrid (AGR) and Con Edison (ED) continue to pursue large transmission projects to reduce congestion into both the Lower Hudson Valley (LHV) and NYC zones. We look for a larger 130-200 mile DC interconnection project (Connect New York) in the coming month as particularly intriguing to put yet further prospective pressure. We expect the capacity spread between upstate and downstate to continue its decline structurally as bottlenecks are resolved, with the LHV zone eventually being eliminated entirely due to both new asset in-service as well as improved transmission. The offset appears to be the potential for LHV exports into New England potentially should prices support this trend. The latest AGR project would be among the first major recent transmission projects put forth by a utility under the NYISO's project solicitation efforts – and an outcome of the long-delayed Energy Highway initiative. The project would similarly enable the

state to more readily accommodate any eventual retirement of Indian Point. Expect details and progress on new project timelines in 2016 (responses are due April 28th)

What's the longer-term forecast for downstate? Limited constraints

We continue to express a more depressed outlook for the downstate regions in NYC and Lower Hudson Valley (LHV) as supply parameters and new capacity provide a lid on prices. We emphasize current prices limit the ability for mitigated assets such as the NJ-NY Hudson Transmission Partners (HTP) project from continuing to clear.

What are the big questions in New York?

- **Nuclear policy to the rescue?:** We look for approval around ~August 1st of the latest effort to put in place a wider 'Zero Emission Credit' Market (ZEC) to keep in place existing capacity? Given the meaningful de-carbonization ambitions for the state and Governor, we see this as a still quite credible angle.
- **Renewable policies scaling: How quickly will this translate?** With New York having recently enacted its own 50% RPS as part of a recent trend, we see this as ensuring continued structural pressures on power prices. As such, we see the state as poised to keep support on capacity prices amidst a need to remunerate generators whose primary revenue sources had previously been oriented energy margins. We look for New York to begin to scale its renewable procurement efforts as a function of wider execution on its RPS goals embedded within the Reforming the Energy Vision (REV) ambitions. Specifically we expect the state to ultimately turn to some longer-dated PPA procurement mechanism to enable the most cost effective procurement of such projects.
- **Gas imports into New York: *not so much?*** The wider question remains whether an effective replacement for the Constitution Pipeline will be found following its recent rejection. While near-term prospects for power have improved on the back of delayed or outright cancelled pipe efforts, they have been effectively swapped with longer-dated concerns for more renewables. Further, in the interim, nuclear retirements have been effectively put off the table; the market had been unclear on this prospect, but confirmation of retirements by ETR for instance of Fitz had largely been internalized into expectations.
- **Will New England keep NY capacity trying to export?** We see a continued argument that elevated New England capacity prices will put structural pressure on New York to continue to push out capacity MWs into this adjacent market. *The question remains at what price?*

ETR continues to state that it will close its FitzPatrick plant.

How to meet the future New York renewable goals? Imports.

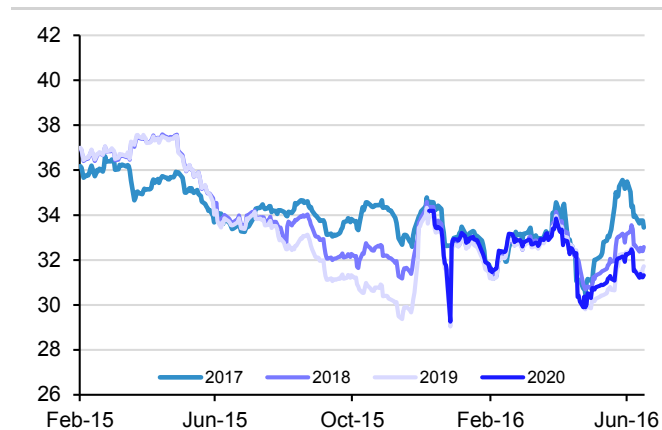
Amidst this focus on transmission, it appears New York state is likely to turn to imports from adjacent regions to source its renewable requirements.

While Blackstone has proposed its long-standing TDI project, we see a wider interest in developing such capacity to expand hydro imports. We think the 50% RPS will be established to include external hydro as qualifying.

Where are power prices trending? Forwards Punished

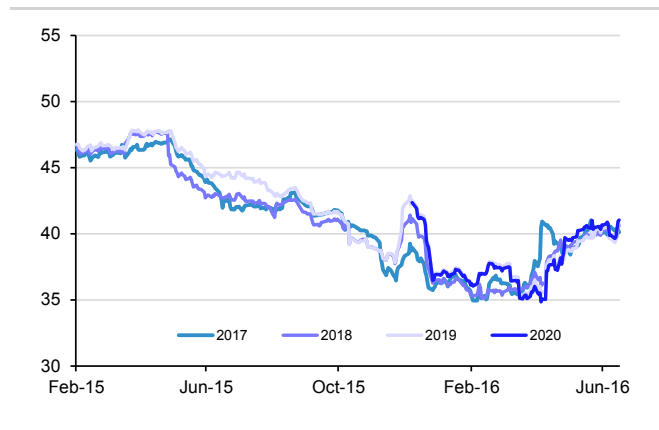
We include the latest Zone A (West), Zone G (Lower Hudson Valley) and Zone J (New York City) ATC prices to illustrate power price trends.

Figure 44: NY-Zone A ATC Power (\$/MWh)



Source: Platts

Figure 45: NY-Zone G ATC Power (\$/MWh)

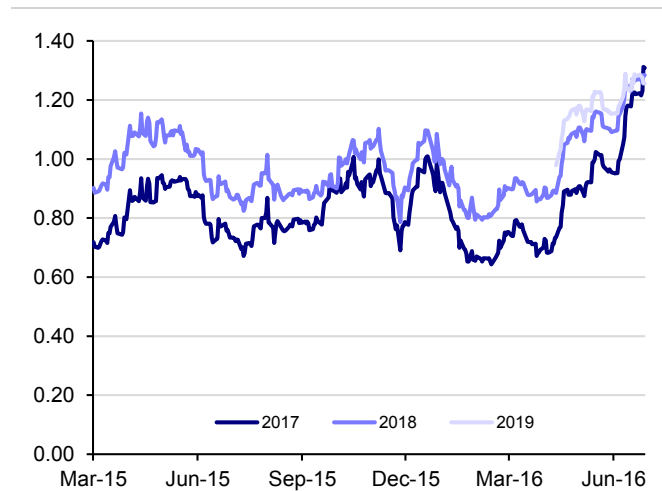


Source: Platts

Finally what about gas basis? Real improvement without the pipes.

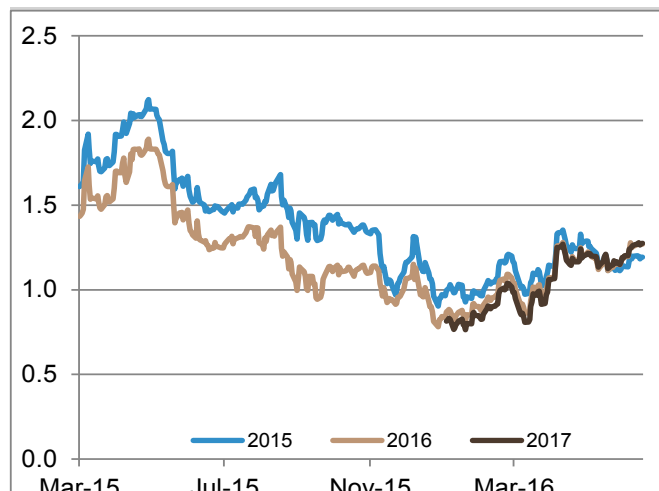
We include the Transco Zn 6 trends as well as Mass Hub price trends below. While muted vs. the highs, both have seemingly recovered in recent weeks as it has become clear the Constitution pipeline project will be delayed service into 2017.

Figure 46: Transco Zone 6 Gas Basis Swap (\$/MMBtu)



Source: Platts

Figure 47: Algonquin Basis Swap (\$/MMBtu)



Source: Platts

And finally, what about sparks on gas assets? Downward.

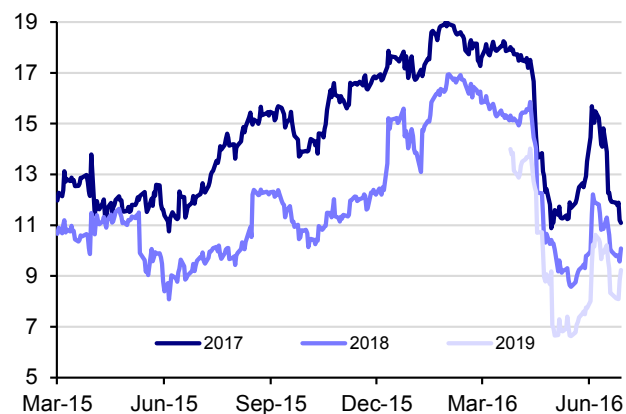
We also include the spark spread trends in each of these markets. We include principally sparks on the Zone G sparks, where most of the contemplated projects are contemplated at present.

**Figure 48: Spark Spread: Zone G @ 7.2 heat rate
(Dom South Gas) (\$/MWh)**



Source: Platts

**Figure 49: Spark Spread: Zone A @ 7.2 heat rate
(Transco Zone 6 Gas) (\$/MWh)**



Source: Platts

For further background we include links to recent reports below:

[7/13/16: Setting the Tone on Nuclear](#)

[4/5/16: Summer Heat Melts Big Apple Capacity Pricing](#)

[2/3/16: Nuclear Lifeline in \[Upstate\] NY](#)

[1/22/16: Taking A Bite out of the Big Apple](#)

[11/3/15: 'Ya Gotta Believe' NY Prices Are Heading Higher](#)

California: Arguing the Near-Term Case

La Paloma is latest victim to weak California Power Markets Prices

In the latest case of Power Market distress, operators of the La Paloma facility have filed an emergency complaint at FERC against the CAISO which rejected the plants petition to pursue unit outages at 3 of the 4 CCGT units at the site. We emphasize the CAISO in this instance also rejected efforts to payout CPM payments or any other form of RMR to ensure the plant could meet its ongoing cash needs; CAISO emphasizes in its response to the complaint that the generator is free to retire, but rather cannot seek a long-duration outage as a mechanism for the retirement. Given the timing of July 1 through November 30, we suspect the rejection of the 206 complaint from FERC would lead to an immediate effort to formally retire, consistent with the process Calpine is pursuing in the case of Sutter. We emphasize the weak economics in the market remain among the worst of any regional market; we suspect other plants will follow the Sutter and La Paloma examples.

The exact reason behind why operators chose this retirement path for La Paloma is unclear, but potentially relates to legacy carbon AB32 credits. Further, a temporary outage through 4Q could enable the plant to pursue more of a seasonal dispatch approach if allowed to continue with such long duration outages.

We think others could be shortly behind La Paloma and Sutter in pursuing similar efforts to exit the state. The question is not if, but rather the pace of such retirements. The further question is whether the CAISO will attempt to retain plants via RMR/CPM arrangements in light of the longer-dated retirement of Diablo Canyon. This is all in contrast to ongoing repowering efforts of Coastal units. We emphasize the plant has indeed been used historically and began commercial operations in 2003.

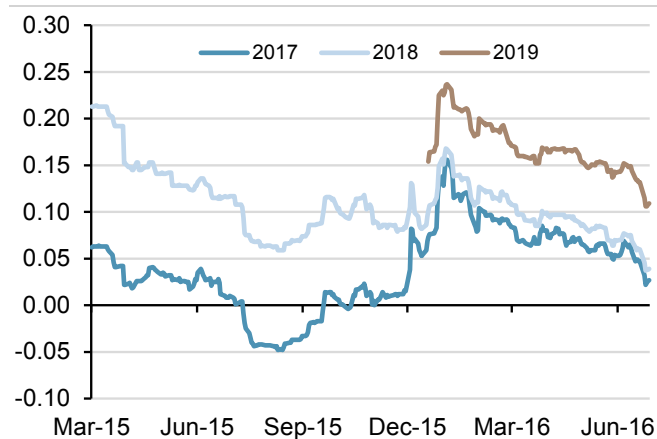
[Link to the complaint](#): FERC Docket EL16-88.

Recovery prospects have moderated expectations for gas premium

Although the leak that resulted from the blowout at the Aliso Canyon facility is plugged, Southern California Gas (SoCalGas – subsidiary of Sempra Energy), the operator of the facility, is prohibited “from injecting natural gas into the underground reservoir” until a safety inspection is completed, according to a report from the California Public Utilities Commission (CPUC). In addition to not being able to provide gas for the energy demands in the region, only one-fifth of the total capacity of the facility remains in the reservoir following the leak. We emphasize the lower supply could cause significant price spikes for generators, and ultimately ratepayers, as the company flows the costs through.

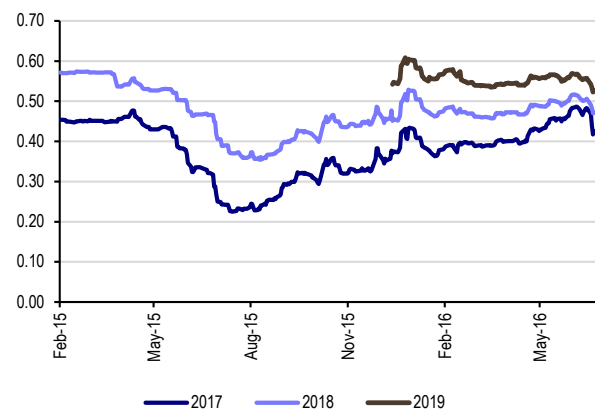
2 CCGTs appear poised to close in the state.. many more are on the come.

Figure 50: SoCalGas Gas Basis (\$/MMBtu)



Source: Platts

Figure 51: PG&E City Gate Gas Basis (\$/MMBtu)



Source: Platts

How long could the storage facility be out?

Aliso Canyon is an integral part of the energy system in SoCal and the constraints put on the facility will have an adverse impact on the service area, especially during the summer and winter months. The report from the CPUC states, *"Without any gas supply from Aliso Canyon, there are 14 days this coming summer during which gas curtailments could be high enough to cause electricity service interruptions to millions of utility customers."*

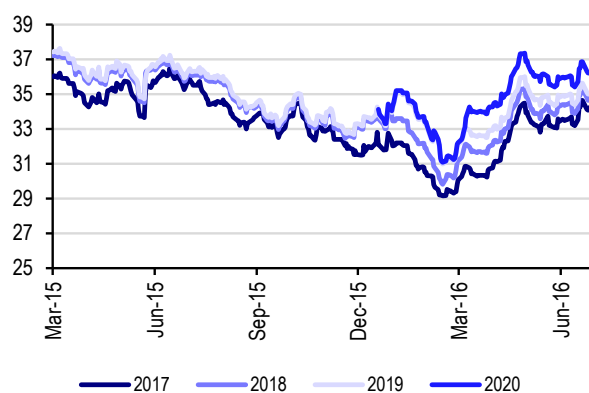
Latest gas leak in PG&E territory

We flag the latest at McDonald Island does not appear as substantial but warrants attention amidst a backdrop of substantial scrutiny of utility gas operations.

What about Power Prices? Resilient.

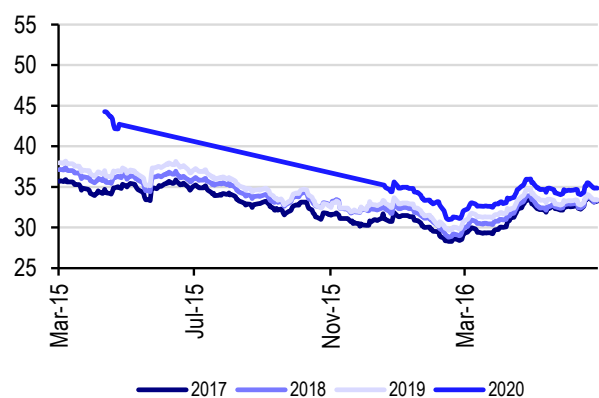
From this, we see power prices as having found a continued floor at current levels. We emphasize prices remains narrowly bunched as the 'marginal' unit remains unchanged throughout much of the period with the gas supply curve with CCGTs pervasive, quite flat.

Figure 52: NP15 ATC Power Prices (\$/MWh)



Source: Platts

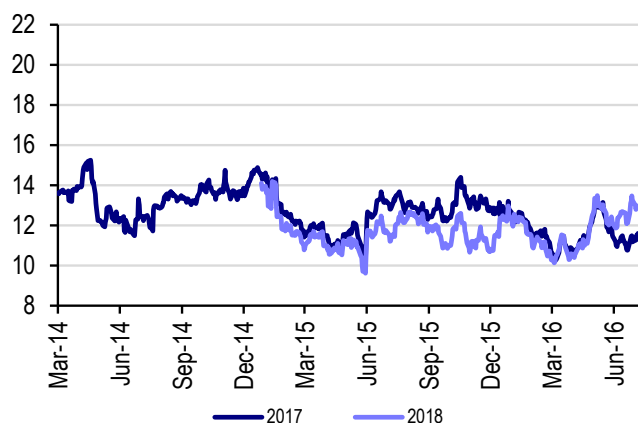
Figure 53: SP15 ATC Power Prices (\$/MWh)



Source: Platts

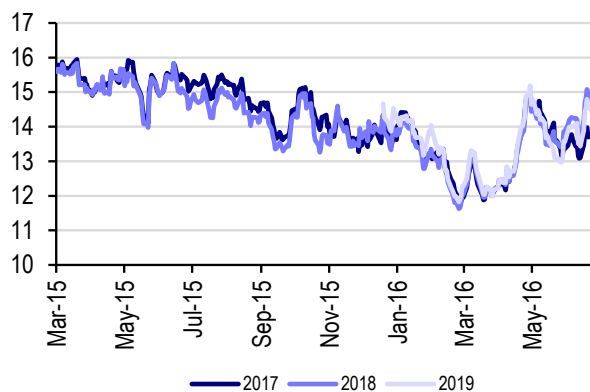
But Sparks have actually kept up of late. Relatively intact still despite gas price pressures. We remain relatively constructive in the near-term as plant retirements are a real prospect alongside higher gas tariffs priced into the market.

Figure 54: NP15 Spark Spread (\$/MWh)



Source: Platts

Figure 55: SP15 Spark Spread (\$/MWh)



Source: Platts

PG&E's Gas Rate Case: Unfavorable but past tense

Yet another driver of power price inflation in the near term is the resolution of the GT&S case for PG&E. We understand the substantial focus on safety-related spending could add upwards to \$1/MMBtu under the pending case (from \$0.35/MMBtu today to ~\$1.35/MMBtu under the proposal). We flag this has substantially impeded the economics for Dynegy's plant in the region and look for details with 2Q results.

We note Calpine is also located in Northern California, largely with non-coastal, interior plants, not exposed to shifts in the pending GT&S case. In fact, the only plant that was materially exposed was Sutter, which was recently mothballed.

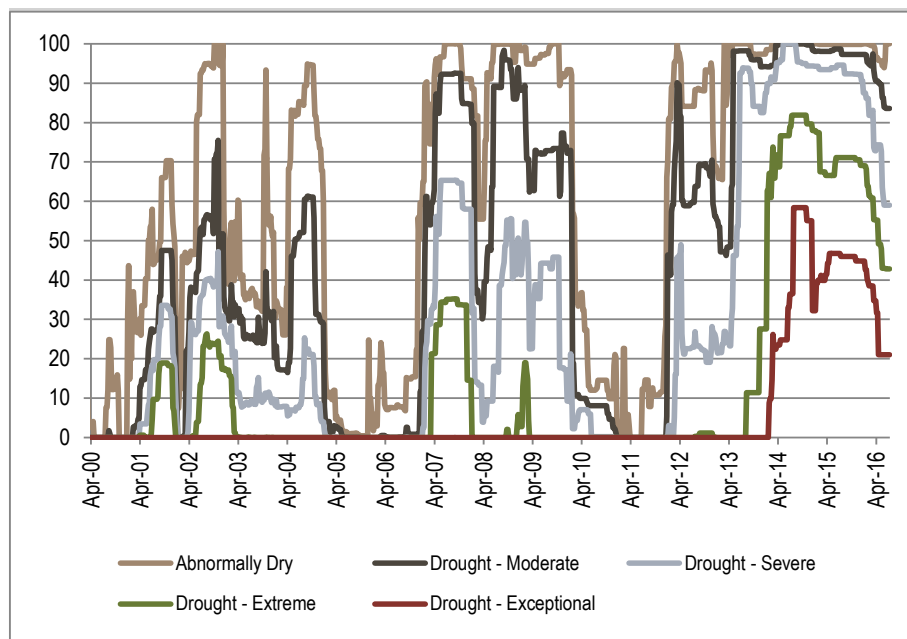
California's drought is substantially moderating

We flag the drought has substantially improved in recent months, driving down both power and gas price expectations. We flag this is coincident with the La Nina conditions widely expected to follow a severe El Nino condition earlier.

We see significant risk of increase to dispatch costs

Easing drought conditions remain the primary headwind to power

Figure 56: Drought Monitor – Easing Conditions offer offset to the otherwise improving outlook



Source: United States Drought Monitor

Risk of Mexican exports from California also of close focus

Following the inaugural capacity auction in recent weeks in Mexico, we see risk for capacity to attempt to de-link from the CAISO to join the Mexican market. We see this as a clear potential for Sempra's TDM facility (albeit potentially under a new owner); this 625 MW facility would be the *first* to leave, but with others potentially following. For instance, Calpine is evaluating exporting capacity from its Otay Mesa plant as well among other options for its large installed base in the state. The plant would otherwise be sold to SDG&E at the conclusion of its existing contract. Further, the question remains whether other assets in Calpine's California fleet could yet take advantage of export rights. We emphasize we have already seen this manifest itself in ERCOT.

For further background we include links to recent reports below:

[6/17/16: The Wild, Wild West](#)

[6/6/16: Breaking the Logjam in California?](#)

[6/2/16: Cruisin' our California Conference](#)

[4/18/16: Arguing the Case for California](#)

[3/31/2016: Can Power Keep Up With Gas?](#)

[2/12/2016: Gas Storage: Framing Aliso Canyon in the Context of Safety](#)

[1/7/2016: West Waiting for a Better 2H16](#)

Where's the UBS Gas Forecast?

Below we include commentary from our oil & gas colleagues from their July 6th note [\[please click here for the full report\]](#).

- We are raising our 3Q16 and 4Q16 NYMEX natural gas price forecasts (\$/MMBtu) to \$2.80 and \$3.00 (vs. \$2.25 and \$2.60 prior), respectively, increasing our FY16 forecast from \$2.25/MMBtu to \$2.45/MMBtu. The upward revision is due to better than expected demand which has been driven by improved visibility from hot weather and increased coal-to-gas fuel switching from low prices through 2Q, both of which has left storage on track to start next winter at ~3.90 Tcf (~100 Bcf above normal but below the ~4.0 Tcf we were forecasting at the start of the injection season). Our revised 3Q and 4Q forecasts are above consensus (\$2.33 and \$2.50) but near the current futures strip (\$2.81 and \$2.98) as we believe some demand will be lost back to coal as prices rise have risen from ~\$2/MMBtu in 1H16 to ~\$2.90 for July bid week, partly offset by declining production from reduced drilling activity and infrastructure constraints in the northeast. We've left our 2017, 2018, and long-term normalized (2019+) price forecasts (\$/MMBtu) unchanged at \$3.00, \$3.00, and \$3.25, respectively.

We show below latest UBS forecast for US nat gas:

Figure 57: Revised UBS Oil and US Natural Gas Price Forecasts (2016-20E and Normalized)

	2014A	2015A	1Q16A	2Q16A	3Q16E	4Q16E	2016E	2017E	2018E	2019E	2020E	Normalized
WTI (\$/Bbl)	\$92.89	\$48.81	\$33.64	\$45.59	\$47.00	\$49.00	\$43.81	\$57.00	\$67.00	\$72.00	\$72.00	\$72.00
Previous Estimate				\$38.00	\$41.00	\$46.00	\$39.68	\$52.00	\$67.00	\$72.00	\$72.00	\$72.00
First Call Consensus					\$45.25	\$50.00	\$43.62	\$54.00	\$61.00	\$66.50	\$68.75	NA
Futures Strip Price					\$47.53	\$49.19	\$43.99	\$51.34	\$53.32	\$54.57	\$55.65	NA
UBS vs Consensus					4%	-2%	0%	6%	10%	8%	5%	NA
UBS vs Strip prices					-1%	0%	0%	11%	26%	32%	29%	NA
Brent (\$/Bbl)	\$99.38	\$53.57	\$35.32	\$47.41	\$50.00	\$52.00	\$46.18	\$60.00	\$70.00	\$75.00	\$75.00	\$75.00
Previous Estimate				\$41.00	\$44.00	\$49.00	\$42.35	\$55.00	\$70.00	\$75.00	\$75.00	\$75.00
First Call Consensus					\$47.00	\$50.00	\$45.07	\$56.00	\$64.00	\$69.00	\$70.00	NA
Futures Strip Price					\$48.59	\$50.05	\$45.48	\$52.51	\$55.22	\$57.25	\$59.16	NA
UBS vs Consensus					6%	4%	2%	7%	9%	9%	7%	NA
UBS vs Strip prices					3%	4%	2%	14%	27%	31%	27%	NA
Natural Gas NYMEX (\$/MMBtu)	\$4.45	\$2.67	\$2.09	\$1.95	\$2.80	\$3.00	\$2.45	\$3.00	\$3.00	\$3.25	\$3.25	\$3.25
Previous Estimate				\$2.00	\$2.25	\$2.60	\$2.25	\$3.00	\$3.00	\$3.25	\$3.25	\$3.25
First Call Consensus					\$2.33	\$2.50	\$2.22	\$2.89	\$3.00	\$3.01	\$3.01	NA
Futures Strip Price					\$2.81	\$2.98	\$2.46	\$3.15	\$3.03	\$3.02	\$3.06	NA
UBS vs Consensus					20%	20%	10%	4%	0%	8%	8%	NA
UBS vs Strip prices					0%	1%	0%	-5%	-1%	8%	6%	NA

Source: UBS estimates, FactSet, and Bloomberg

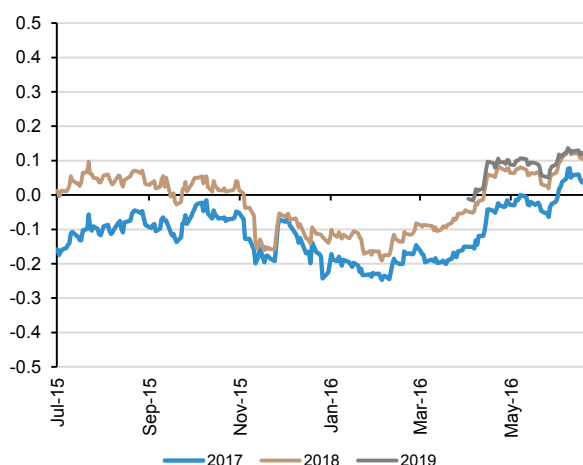
What about Gas Basis Trends of Late?

Dominion-South and TETCO

Gas basis little changed for either TETCO or Dominion South in recent months. Given delays in pipelines TETCO prices are improving of late. We suspect prices will continue to improve as other contemplated New York and New England projects potentially face headwinds.

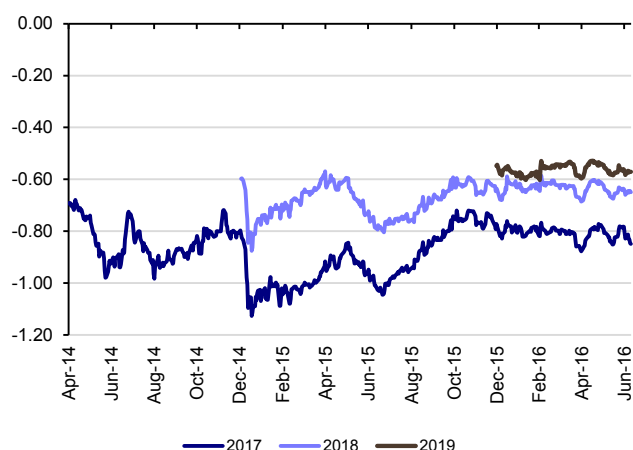
Despite delays in pipelines (and hence concerns of limited takeaway capacity), Dom-South has failed to deteriorate in recent months,

Figure 58: TETCO M3 Basis Swap (\$/mmbtu)



Source: Platts

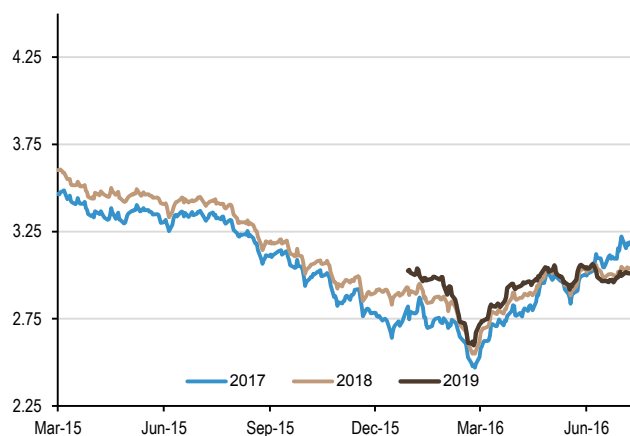
Figure 59: Dominion South Basis Swap (\$/mmbtu)



Source: Platts

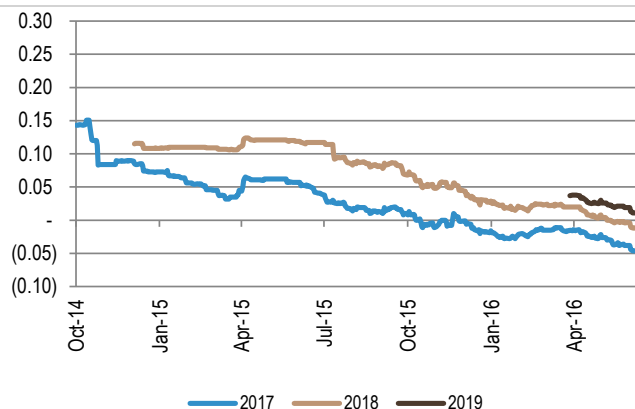
Henry Hub has stabilized in recent weeks while the Houston ship channel basis continues to decline. We suspect declines in Houston Ship to be attributable to growing regional Supply expectations once more.

Figure 60: Henry Hub (\$/mmbtu)



Source: Factset

Figure 61: Houston Ship Channel Swap Basis (\$/mmbtu)



Source: Platts

Where did spot prices trend?

We include actual spot prices across several key markets below for 2Q, which shows some improvement from 1Q but substantial declines on a YoY basis.

Figure 62: Peak Spot Power Prices

Power Price \$/MWh								
Quarter End	PJM West	PJM East	CAISO	ERCOT	MISO Indiana	MISO Illinois	NEISO	NYISO
6/30/2016	32.9	28.8	27.3	21.3	32.0	28.6	28.2	28.4
3/31/2016	29.6	31.4	23.9	19.0	31.4	25.9	29.4	29.3
12/31/2015	30.6	28.5	31.5	21.1	37.3	25.6	30.5	25.0
9/30/2015	38.1	40.5	40.1	33.0	38.1	32.0	38.5	36.6
6/30/2015	37.7	37.1	25.7	27.2	37.0	29.7	29.0	32.8
3/31/2015	57.3	67.4	32.3	26.5	44.4	31.9	87.0	78.3
12/31/2014	39.9	48.3	43.0	33.6	58.9	35.6	46.1	41.4
9/30/2014	41.6	45.4	49.7	37.1	35.2	36.4	40.7	40.1
6/30/2014	48.3	51.5	45.6	41.0	37.9	46.1	42.9	44.0
6/30/2016 vs 6/30/2015	-13%	-22%	6%	-22%	-14%	-4%	-3%	-13%

Source: Bloomberg

Nat Gas was rising, but sparks proved resilient

PJM east was the only exception to the overall upward trend QoQ, albeit off a very low base in Q1 and generally down YoY spark spreads. CAISO showed substantial improvement in the quarter, however

Figure 63: Qtr Avg Spark Spreads @7.2 Heat Rate

7.2 HR Spark Spread \$/MWh						
Quarter End	PJM West	PJM East	CAISO	ERCOT	NEISO	NYISO
6/30/2016	21.7	17.6	11.5	6.5	12.1	16.3
3/31/2016	16.7	18.5	8.0	5.2	11.9	10.7
12/31/2015	21.5	19.4	12.0	6.0	8.4	11.4
9/30/2015	28.5	31.0	17.5	13.4	21.8	21.0
6/30/2015	26.4	25.8	3.7	7.8	13.1	15.1
3/31/2015	16.5	26.5	10.3	6.7	2.5	15.5
12/31/2014	20.6	29.0	12.8	7.3	8.3	19.0
9/30/2014	24.3	28.1	16.9	8.6	19.0	22.4
6/30/2014	22.4	25.5	9.2	8.2	12.5	17.9
6/30/2016 vs 6/30/2015	-18%	-32%	212%	-17%	-8%	8%

Source: Bloomberg

Forward ATC Heat Rates

We include the latest forward heat rate outlook by market.

Figure 64: Forward ATC Heat Rates (MWh/MMBtu) by Power Market

	2016	2017	2018	2019
NP15 / PG&E	11.65	10.43	10.86	10.65
YoY % Change		-10.4%	4.1%	-2.0%
ERCOT-S/Houston Shipping	12.44 	12.38 	12.84 	12.51
YoY % Change		-0.6%	3.8%	-2.6%
NYISO Zn G / Transco Zn 6	15.16 	10.75 	11.25 	10.87
YoY % Change		-29.1%	4.6%	-3.4%
Southern / Transco Zn 4	11.44 	10.55 	10.55 	10.05
YoY % Change		-7.8%	0.0%	-4.7%
Mass Hub / Algonquin	11.10 	10.87 	11.01 	10.95
YoY % Change		-2.1%	1.3%	-0.5%
Entergy / Henry Hub			11.97 	11.77
YoY % Change				-1.7%
NI Hub / Chicago Citygate	13.46	11.27	12.03 	11.16
YoY % Change		-16.3%	6.8%	-7.2%
PJM West / TETCO M3	19.44 	12.82 	12.53 	12.01
YoY % Change		-34.1%	-2.2%	-4.2%
AD Hub / MichCon	14.46 	11.71 	12.34 	11.46
YoY % Change		-19.1%	5.4%	-7.1%
ERCOT-Houston/Houston Ship	12.79 	12.74 	12.91 	12.70
YoY % Change		-0.3%	1.3%	-1.6%
ERCOT-West/Houston Ship	11.88	11.96	12.28 	11.94
YoY % Change		0.7%	2.7%	-2.7%
ERCOT-North/Houston Ship	12.06 	12.05 	12.35 	12.15
YoY % Change		-0.1%	2.4%	-1.6%
CIN-Hub/ Chicago Citygate	13.37 	11.64 	12.31 	11.20
YoY % Change		-12.9%	5.7%	-9.0%
Average		-11.0%	3.0%	-3.7%
1Q16 Average		-7.1%	-2.1%	-2.6%
4Q15 Average		-8.6%	-2.4%	1.5%
3Q15 Average		-3.7%	-5.5%	1.5%
2Q15 Average		-2.6%	-2.4%	1.3%
1Q15 Average		-3.5%	-2.7%	1.3%

Source: Platts, UBS

Regional Heat Rate Trends

The picture for regional heat rates is mixed with expansion in most parts of the country with New York and the Midwest as notable exceptions.

Figure 65: ATC Heat Rates – Change YoY for Forward 2017 (btu/Kwh)

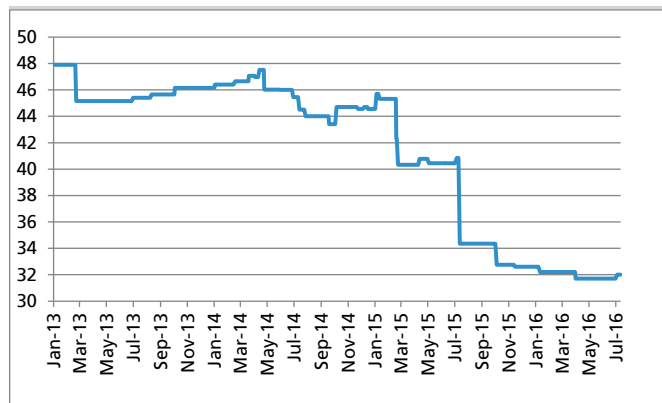
ATC Heat Rates 2017					
	ERCOT-North	ERCOT-Houston	ERCOT-West	ERCOT-S	Southern
Jul-16	9,625	10,317	9,414	9,845	9,273
Jul-15	9,201	9,963	8,987	9,410	9,428
YoY % Change	5%	4%	5%	5%	-2%
	NY-ZnG	NY-ZnJ	NY-ZnA	MassHub	
Jul-16	8,968	9,630	10,085	9,269	
Jul-15	10,394	10,982	10,212	9,667	
YoY % Change	-14%	-12%	-1%	-4%	
	PaloVerde	SP15	NP15	MidC	
Jul-16	12,035	10,859	9,537	7,903	
Jul-15	11,323	10,531	9,692	8,194	
YoY % Change	6%	3%	-2%	-4%	
	Indy Hub	NI Hub	ADHub	PJM-W	
Jul-16	9,801	9,199	9,965	10,704	
Jul-15	10,295	9,398	10,651	11,460	
YoY % Change	-5%	-2%	-6%	-7%	

Source: Platts, Bloomberg

Coal Price Trends

Coal prices remain weak, however, could well see a recovery in pricing as the inventory backlog is addressed. [Please see our wider note from yesterday.](#)

Figure 66: Illinois basin coal prices



Source: Bloomberg

Figure 67: PRB coal prices



Source: Factset

Capacity Price Projections by Region

We reflect the summary of our latest historical and projected capacity prices below including the latest from New England, New York, MISO and PJM.

Figure 68: Capacity Market Projections by Region

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
PJM (\$/MW-day)													
RTO	111.9	102.0	174.3	110.0	16.5	27.7	126.0	136.0	134.0	151.5	164.8	100.0	125.0
EMAAC	148.8	191.3	174.3	110.0	139.7	245.0	136.5	167.5	134.0	151.5	225.4	119.8	144.8
SWMAAC	210.1	237.3	174.3	110.0	133.4	226.2	136.5	167.5	134.0	151.5	164.8	100.0	125.0
MAAC				110.0	133.4	226.2	136.5	167.5	134.0	151.5	164.8	100.0	125.0
DPL-S			186.1	110.0	222.3	245.0	136.5	167.5	134.0	151.5	225.4	119.8	144.8
PS-N					185.0	245.0	225.0	167.5	134.0	151.5	225.4	119.8	144.8
PSEG					139.7	245.0	136.5	167.5	134.0	151.5	225.4	119.8	144.8
PEPCO						247.1	136.5	167.5	134.0	151.5	164.8	100.0	125.0
ATSI								357.0	134.0	151.5	164.8	100.0	125.0
ComEd						27.7	126.0	136.0	134.0	151.5	215.0	202.8	202.8
PPL						226.2	136.5	167.5	134.0	151.5	164.8	100.0	125.0
ISO-NE													
Annualized (\$/kW-Month)	3.65	3.95	4.19	3.59	2.78	2.53	2.72	3.02	2.99	5.30	8.50	8.08	7.03
Clearing Price/Pro-Rated	3.75	4.10	4.25	3.12	2.54	2.52	2.86	3.13	2.88	7.03	9.55	7.03	7.03
NYISO - Zn J													
Summer ICAP (\$/kW-month)	6.50	6.75	12.90	13.54	11.70	14.80	16.24	15.50	10.00	10.00	11.00	11.00	11.00
Winter ICAP (\$/kW-month)	1.91	2.79	4.65	4.60	2.70	4.50	7.54	8.45	6.67	6.67	6.67	6.67	6.67
NYISO Zn J (\$/kW-month)	4.35	5.08	8.77	8.75	7.50	10.16	12.04	11.68	8.34	8.34	8.84	8.84	7.72
NYISO Zn J (\$/kW-yr)	52.22	60.96	105.20	105.04	90.00	121.88	144.50	140.14	100.02	100.02	106.02	106.02	92.68
NYISO - RoS													
Summer ICAP (\$/kW-month)	2.67	3.01	2.47	0.55	1.25	5.80	5.15	3.50	4.25	4.96	5.00	5.00	5.00
Winter ICAP (\$/kW-month)	1.91	1.77	1.75	0.39	0.15	0.82	2.58	2.90	2.35	2.35	2.35	2.35	2.35
NYISO - RoS (\$/kW-month)	2.27	2.39	1.88	0.43	0.81	2.80	3.92	3.11	3.30	3.65	3.67	3.67	3.28
NYISO - RoS (\$/kW-yr)	27.20	28.64	22.60	5.16	9.74	33.64	47.02	37.29	39.57	43.85	44.07	44.07	39.38
NYISO - LHV													
Downside case - assumption	2.67	3.01	2.47	0.55	1.25	4.20	5.15	3.50	3.62	4.96	5.00	5.00	5.00
Winter ICAP (\$/kW-month)	1.91	1.77	1.75	0.39	0.15	0.82	2.58	2.90	1.25	2.35	2.35	2.35	2.35
NYISO - RoS (\$/kW-month)	2.27	2.39	1.88	0.43	0.81	2.80	3.92	2.93	2.62	3.65	3.67	3.67	3.28
NYISO - RoS (\$/kW-yr)	27.2	28.64	22.6	5.16	9.74	33.64	47.02	35.10	31.41	43.85	44.07	44.07	39.38
MISO Capacity Values:													
IPA Auctions (\$/kW-yr)	12.41	8.46	0.67	0.18	3.70	0.38	6.11						
Calendarized (\$/kW-yr)		10.44	4.57	0.43	1.94	2.04	3.25						
MISO RA Auction (\$/MW-day)						1.05	16.75	150.00	72.00	72.00	72.00	72.00	72.00
Calendarized (\$/KW-yr)							3.73	34.48	38.14	26.28	26.28	26.28	26.28

Source: PJM and UBS (Note: actual and forecasts prices for PJM represent base capacity auction prices)

Power Market Preferences

We continue to prefer ERCOT, albeit remain cautious on the long term across all US Power markets. seeing that market as being closest to the bottom with more retirements coming later in the decade due to poor economics and impending environmental rules.

We have switched CAISO and MISO at the bottom with California improving in our view based upon the latest issues of gas storage that should be supportive to power prices. We increasingly see NYISO as the most concerning given the twin impacts of Zero Emission Credits (ZECs) keeping nuclear and forthcoming 50% RPS.

We are raising MISO to reflect our expectations for an improving trend on capacity prices out of its pending reforms. We emphasize recovery given the Clinton nuclear plant retirement appears to be coming on the margin

We are maintaining ISO-NE, although we see the forthcoming Mass legislation risk as a clear potential downside given the size of the potential RFPs out of the state, accounting for ~30-40% of total new renewables procured. We emphasize capacity prices are trending lower, albeit have more limited structural downside given existing rules.

More renewables? The sobering side of Power.

We see expanded efforts to procure renewables in New York and New England as driving our reduced expectations. The question remains timeline, seeing NIMBY concerns and protracted development of corresponding transmission limiting this to a medium-to-longer term impact (albeit a potentially large one at that). Transmission from Canada of Hydro remains alive and well – and a likely reality for IPPs in both regions.


What has changed in our power market preferences?

Up on CAISO and PJM

Less on ISO-NE and NYISO on growing renewable concerns

ERCOT's the only *rea*/market we have confidence in medium-term improvement

Figure 69: Power Market Preferences

UBS Preferred Power Market List - Rank Order				
Preference	New Rank	Old Rank	Market	Reasoning
Most Preferred 	1	1	ERCOT	New entry slowing, with regulatory reforms back on the table, its time for asset retirements, finally.
	2	2	ISO-NE	Latest capacity retirements and reforms should provide some resiliency to pricing
	3	3	PJM	Reforms largely reflected-- support on capacity offset by continued new gas entry
	4	6	MISO	Combo of low-cost wind and challenging market construct. Potential DYN/EXC retirements will be key
	5	5	CAISO	Increasing gas prices from Aliso Canyon leak and GT&S rate case should help in near-term
Least Preferred	6	4	NYISO	We see new gas and new supply as driving down capacity prices

Source: USB Estimates

Ameren Corp.

Despite its discount, we see continued risks that AEE may see negative impacts in the lower rate cycle due its 30-year treasury exposure, pending Missouri rate case, as well as MtM impact from ongoing FERC ROE complaints.

We forecast 2Q16 adjusted EPS of **\$0.50** vs \$0.58 in 2Q15 and \$0.53 Consensus.

2Q would have been approximately flat YoY if not for the impact of the Callaway outage.

- **Key Drivers:** Higher revenue from transmission investments and rate relief provide the foundation for YoY growth but this is fully offset by the Spring nuclear outage and lost sales due to Noranda and energy efficiency.
- **Wildcard Factors:** (1) Negative impact of the decline in US Treasuries on the IL Electric business [management booked to a 2.95% ROE in 2Q15 vs ~2.1% today] and [datapoints on FERC transmission ROEs](#) [9.7%]; (2) mitigation of lost Noranda load; and (3) impact of energy efficiency – AEE expects to book some of the expected ~\$19Mn performance incentive later in 2016 (likely 2H16) to help offset the effects of the program in 2016.

Figure 70: AEE 2Q16E Earnings Walk

Ameren Corp 2Q16 Earnings Walk		EPS
2Q15A Adjusted EPS	<i>Notes</i>	\$0.58
Weather vs Normal in 2Q15	<i>Return to Normal Weather; Flat vs Normal</i>	0.00
Weather vs Normal in 2Q16	<i>Degree Days in Current Year; Near-Normal</i>	0.00
MO Electric: New Rates	<i>\$122Mn Increase Effective May 30, 2015</i>	0.01
MO Electric: Energy Efficiency Impact	<i>\$19Mn of performance incentive (2H16E); flattish sales in 2016</i>	(0.02)
IL Electric: Higher Rates (Formulaic)	<i>\$106Mn Increase Effective January 2016; 30Yr Treasuries ↓</i>	0.01
ATX and IL Transmission	<i>Avg Ratebase increase YoY for FERC Trans. is \$700M Higher in '16</i>	0.04
IL Gas: Higher Rates	<i>\$45Mn Increase Effective Late December 2015; ~50bp ROE ↑</i>	0.02
Interest Expense	<i>Issued \$350Mn (2.7%) and \$350Mn (3.65%) at Parent on Nov. 24</i>	(0.01)
Effective Tax Rate	<i>~37-38% ETR for 2Q-4Q16; ~37% in 2Q15 from tax position</i>	(0.00)
Callaway Refueling Outage	<i>Impact of Callaway Nuclear Refueling Outage During Spring 2016</i>	(0.09)
Impact of Noranda	<i>Forgone sales net of mitigation; ceased operations</i>	(0.03)
Absence of 1Q15 ICC Power Usage Item	<i>Removing Impact of ICC Recovery</i>	0.00
Change in O&M, D&A, and Other	<i>Organic cost inflation offset by lean initiatives in Missouri</i>	0.00
Dilution	<i>Minimal impact</i>	(0.00)
2Q16E Adjusted EPS		\$0.50
2Q16 Consensus		\$0.53
2016 UBSe EPS		\$2.48
2016 Consensus		\$2.51
2016 Guidance		\$2.40-\$2.60

Source: Company filings, FactSet, UBS estimates

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

[5/12/16 Leaving The Door Open](#)

[4/20/16 Well Positioned](#)

[3/10/16 Working Together This Time](#)

[11/6/15 Solid Execution Continues](#)

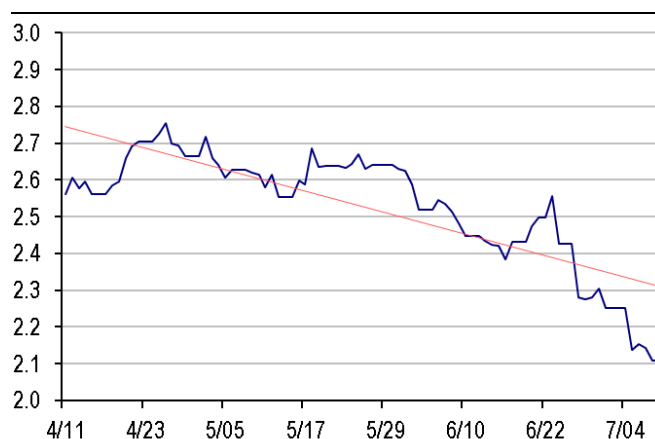
[8/4/15 Following The Regulatory Path to Illinois Growth](#)

Figure 71: 30-Year Treasury Rate (Long-Term)



Source: FactSet

Figure 72: 30-Year Treasury Rate (Trailing Three Months)



Source: FactSet

What are the key updates for AEE?

- Among the most exposed company to lower ROE trend via both T&D rates:** Ameren is one of the most exposed companies in our view to the evolving negative rate environment, both given its exposure to MISO ROEs (via FERC ratebase, for which an explicit ROE assumption is not provided) as well as via its formulaic ROEs in Illinois (tracked to 30-year treasuries: 3.2% 2016 assumption in guidance vs. 2.6% YTD average and ~2.1% at present). Despite an above-average EPS growth rate of 5-8%, we see pressures through the medium-term as management seemingly indicated that the high-end of its EPS growth target was based on higher authorized ROEs for Illinois electric.

For example in its current Illinois electric rate case AEE is requesting an 8.64% ROE based on the 580bp + 30Yr Treasury formula versus a 9.14% ROE in the previous case. This request implies a 2.84% average 30Yr Treasury yield in contrast to ~2.1% today. With ratebase increasing and a roll-off of charges for prior under-recovery, we would expect a lower impact on earnings.

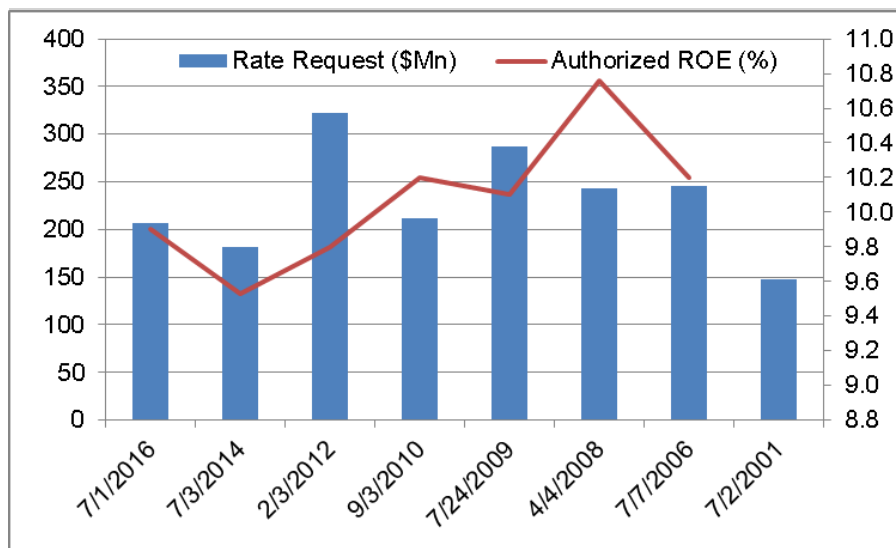
- Missouri in focus with two new rate cases:** On July 1st both GXP and AEE filed rate increase requests with the Missouri Public Service Commission (PSC) with 9.9% ROEs. This contrasts with a 9.53% authorized in the April 2015 for Ameren and 9.5% authorized in September 2015 for GXP. We see risk to the ROEs with Ameren's expert utilizing a "near-term" projected 30Yr Treasury yield of 3.08% vs ~2.1% today and 2.65% "current" when the testimony was prepared. The companies' requests involve significant rate inflation with GXP requesting a +7.5% rate increase and AEE asking for +7.8% base rate increase. With interest rates Ameren's \$206Mn annual revenue request increase includes +\$51Mn for lower sales volume and is requesting to amortize \$81Mn of lost fixed cost recovery related to Noranda over ten years. Investors have expressed an increased interest in Ameren lately based on the perception that the regulatory construct in Missouri is improving and these two cases will be a key barometer. As we show below, ROEs have been trending lower in Missouri while Ameren has requested \$900Mn of high revenues in its last four rate cases covering a six-year period.

We estimate every 50bp reduction in ROEs could result in a **-\$0.025 EPS impact on a full-year basis in Illinois where allowed ROEs are tied to 30Yr US Treasury yields**

The latest IL rate case has a rate decrease due in part to lower ROE assumptions.

Between its latest MO rate case, the formula electric rates in Illinois, and FERC transmission, we see AEE is one of the more sensitive companies to interest rates.

Figure 73: Ameren Missouri Electric Rate Requests



Source: SNL Energy. *2016 ROE is requested

- Not throwing in the towel after failed legislative effort in Spring 2016:**
 Although the effort to pass supportive energy legislation in Missouri were ultimately unsuccessful earlier this year, we see two efforts currently ongoing as potentially improving the investment construct in the state. In the legislation the state Senate has formed the Senate Interim Committee on Utility Regulation and Infrastructure Investment to review the construct for electric and gas utilities in the state relative to peer states to see if there are areas for improvement. The committee is expected to draft a report by the end of the year with recommendations going to the president of the state Senate. At the PSC there is a working case with a similar objective of reviewing the investment construct for electric utilities. Stakeholders have been providing comments and the Staff is expected to issue a report with recommendations by October 17th with a final report due by December 1st with possible PSC actions to take.

Reducing EPS Estimates

We are reducing our EPS estimates in light of the latest step-down in US treasury yields as discussed above which directly impacts IL electric and FERC transmission assets as well as indirectly being a factor in the pending MO electric rate case.

Figure 74: Ameren EPS Estimates


Consolidated EPS Projections	2014A	2015A	2016E	2017E	2018E	2019E	2020E	CAGR 'Adj.16-'20E
Ameren Missouri	1.60	1.62	1.39	1.56	1.60	1.63	1.66	2.3%
Ameren Illinois	0.82	0.88	0.94	1.03	1.12	1.24	1.38	9.9%
ATXI	0.06	0.13	0.22	0.26	0.30	0.33	0.37	13.9%
Other	(0.07)	(0.07)	(0.07)	(0.07)	(0.07)	(0.07)	(0.08)	
Total EPS	2.40	2.56	2.48	2.78	2.95	3.13	3.33	6.1%
Prior	2.40	2.56	2.48	2.80	3.00	3.20	3.43	
YoY Growth Rate	15%	6%	-3%	12%	6%	6%	6%	
Consensus	2.40	2.56	2.51	2.79	3.00	3.21		
Projected ROEs, by Utility (regulatory basis)								
Missouri	10.56%	10.58%	9.00%	9.89%	9.93%	9.94%	9.92%	
Illinois (wtd avg Utes & Transmission)	<u>9.13%</u>	<u>9.71%</u>	<u>9.71%</u>	<u>9.56%</u>	<u>9.34%</u>	<u>9.23%</u>	<u>9.14%</u>	
Weighted Average ROE Earned (regulatory)	10.06%	10.25%	9.22%	9.79%	9.74%	9.72%	9.67%	
Guidance 5%-8% off normalized 2016 \$2.63 (excludes lost -\$0.13 from Noranda)								
Low Implied Guidance Range (5%) off normalized 2016 \$2.63			2.40	2.76	2.90	3.04	3.20	
High Implied Guidance Range (8%) off normalized 2016 \$2.63			2.60	2.84	3.07	3.31	3.58	
'16-'20 UBSe EPS CAGR off normalized 2016 \$2.63							6.1%	

Source: Company filings, FactSet, UBS estimates

Valuation: Increase Price Target to \$53 from \$49

Our valuation is based on a 2018E sum-of-the-parts. We are increasing our price target by \$4 which is driven by the 2x-turn improvement in regulated utilities (to ~18x from 16x). The +\$5/sh increase for the peer multiple expansion is offset by the -\$1/sh due to lower forward EPS estimates.

Figure 75: AEE Sum-of-the-Parts Valuation

Ameren Sum of the Parts Valuation - 2018E UBSe 									
All figures in \$Mn except per share									
	EPS		P/E Multiple				Equity Value		
	Low	High	Peer Multiple	Prem /Disc	Base	High	Low	Base	High
Ameren Missouri	1.60	16.8x	17.8x	0.0x	17.8x	18.8x	\$6,544	\$6,934	\$7,323
Ameren Illinois	1.12	17.3x	17.8x	0.5x	18.3x	19.3x	\$4,726	\$4,999	\$5,273
Ameren Transmission (ATXI)	0.30	18.3x	17.8x	1.5x	19.3x	20.3x	\$1,317	\$1,389	\$1,461
Parent Unallocated Items	(0.07)	16.8x	17.8x	0.0x	17.8x	18.8x	(\$286)	(\$303)	(\$320)
Total / Implied Utilities	2.95	17.1x			18.1x	19.1x	\$12,302	\$13,019	\$13,737
2018E Number of Shares Outstanding (Mn)							244	244	244
Equity Value per Share							\$50.00	\$53.00	\$56.00
Upside/(Downside)							-5%	1%	7%

Source: Company filings, FactSet, UBS estimates

American Electric Power

Shares continue to outperform as the market waits for updates on the sales process for the 'non-PPA assets' but the question is whether public equity concerns about IPP valuations will impact the process. The 'PPA assets' are the more interesting debate where management has indicated it could advocate for Ohio re-regulation but this appears to be a post-election item. A more comprehensive regulated update is expected at EEI or with a 2017 Analyst Day when more visibility is achieved.

We forecast 2Q16 adjusted EPS of **\$0.88** vs \$0.88 in 2Q15 and \$0.89 Consensus.

- **Key Drivers:** New rate relief at the regulated utilities and cost reduction efforts should deliver solid growth at the integrated and T&D utilities but this could be largely offset by a difficult comparison at the merchant GenCo YoY.
- **Wildcard Factors:** (1) Performance at the generation & marketing business which is expected to be a headwind again (-\$0.24 in 1Q16) but less of a YoY drag as the RSR ended on May 31st; (2) Magnitude of cost cut efforts following -\$0.11 weather headwind in 1Q16. Following the previous two years of accelerated ~\$74M operations and maintenance spending, management is targeting a reduction of about \$200Mn in 2016 to \$2.8B; and (3) Sales trends, particularly in the shale- and oil-related territories.

For the first integrated utility in our quarterly playbook we look for a flat quarter YoY with regulated growth being offset by a challenging merchant comparison – we expect this trend to continue for peers.

Figure 76: AEP 2Q16E Earnings Walk

American Electric Power 2Q16 Earnings Walk	EPS
2Q15A Adjusted EPS	\$0.88
Vertically Integrated Utilities	\$0.08
Rate Changes	\$0.07
O&M	\$0.07
AFUDC	(\$0.03)
Weather	
Return to Normal	(\$0.01)
Current Quarter	\$0.03
Off-System Sales (OSS)	(\$0.01)
Normal Load	\$0.02
Depreciation and Other	(\$0.02)
Trans. & Distribution Utilities	\$0.03
Rate Changes	\$0.02
O&M	\$0.04
Depreciation	(\$0.01)
Normal Load & OSS	(\$0.02)
Transmission HoldCo	\$0.02
Generation & Marketing	(\$0.12)
AEP River Operations	\$0.00
Corporate & Other	\$0.00
2Q16E Adjusted EPS	\$0.88
2Q16 Consensus	\$0.89
2016 UBSe EPS	\$3.70
2016 Consensus	\$3.66
2016 Guidance	\$3.60-\$3.80

Source: Company Filings, FactSet, and UBS Estimates

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

[4/29/16 Moving to Plan B for the PPA](#)

[3/31/16 Scoring a contract](#)

[1/29/16 Bonus Appreciation](#)

[12/15/15 Another Big Splash in Ohio](#)

[12/7/15 Buying into Ohio](#)

[10/26/15 Love it or List it...Ohio Edition](#)

[9/18/15 Embedding the Auction Uplift](#)

[7/24/15 Marching to a Regulated Tune](#)

What are the key updates for AEP?

- **Latest Ohio developments have extended the timeline for plan to become fully regulated:** Management now expects to have an announcement on the pending sales process for the 'non-PPA' assets in 3Q16 and has received "several bids". These plants up for sale produce ~80% of AEP's merchant EBITDA and include the 2.7-GW Gavin coal plant (Ohio), the 840-MW Waterford combined cycle plant (Ohio), the 507-MW Darby gas peaker (Ohio), and the 1.2-GW Lawrenceburg combined cycle in Indiana.

Amidst the ongoing scrutiny of the AEP portfolio we include further notable comments on the portfolio for sale

Darby: On this 507 MW peaker, built in 2001, the asset continues to work towards addressing its gas delivery challenges located behind the LDC delivery point. We see this asset as among a handful of assets pursuing compliance strategies to address Capacity Performance (CP) and improve sale price expectations.

Waterford: This 800MW CCGT is the jewel of the AEP Competitive portfolio, benefitting from exceptionally cheap delivered gas out of the Utica shale. By contrast, we think its peer Lawrenceburg CCGT, at 1.1GW, does not appear as attractively positioned with respect to delivered gas prices.

The question of rebasing the EPS growth rate? Yes, risk, but our estimates are intact

We note growing attention on AEP of late, specifically on a potential to rebase its 4-6% EPS growth profile off a lower level as part of its upcoming divestment process. We acknowledge this risk as part of a divestment but reiterate our existing estimates would fit under either under a stand-alone (off a lower utility-only base adjusted for redeployment prospects) or off its existing Utility + Genco EPS (recall the divestment has been readily acknowledged to be potentially immediately dilutive on higher near-year generation EPS).

Separately, AEP is working on a joint process with the remaining merchant assets which were originally included in the PPA proposal. Here an update is expected in the Fall/4Q where more visibility is expected on the Ohio proceedings. AEP has indicated that after the election it will assess whether re-regulated legislation has traction and reassess if it would like to pursue that avenue compared with an outright sale. In the re-regulation scenario the timeline is less certain but management indicated that it was not a "two-year event" on its 1Q16 call.

The path is uncertain but AEP still wants to be more regulated in the future.

Final bids are due in 3Q for the 'non-PPA' assets with an announcement expected during the quarter/with the 3Q call (October).

Depending on the timing of resolution we expect a more comprehensive update at EEI or with a 2017 Analyst Day to better elaborate on the regulated investment opportunity set with incremental spending across the jurisdictions (ex. smart meters in OH).

With multiple scenarios possible

- **Still waiting for PJM 2019/2020 disclosures:** AEP was the only company with meaningful PJM exposure to not publicly disclose the details of how much cleared in the latest 2019/2020 PJM capacity auction. Peer FirstEnergy cleared 85% of its capacity in the 2019/2020 auction after substantially clearing all capacity in the prior year's auction; we believe similar erosion in cleared capacity is possible for AEP. It remains to be seen how the sales processes would influence bidding behaviour and whether management will opt to disclose the clearing results at this time. [Further details on the PJM capacity auction are available here with AEP on page 13.](#)
- **Quieter rate case cycle but KPCo could be coming:** We continue to expect meaningful ROE improvement with a focus on Kentucky and West Virginia following the latest rate relief. KPCo had a 5.5% TTM ROE as of 1Q16 which should increase as we progress through 2016 but management indicated that it could be pursuing another rate case in the state. The only material rate case pending currently is Oklahoma (PSCo) where AEP requested a \$84Mn rate increase in July 2015 (10.5%) and the Staff recommended a +\$32Mn increase (9.25% ROE).

The Oklahoma rate increase was effective in January subject to refund.

Updated EPS Estimates at the GenCo

Our EPS estimates are slightly higher based on the latest commodity mark-to-market for the GenCo but as mentioned we do not know how much capacity

Figure 77: AEP EPS Estimates

AEP EPS Estimates	2014A	2015A	2016E	2017E	2018E	2019E
Utilities	\$2.29	\$2.86	\$3.12	\$3.06	\$3.14	\$3.20
Transmission Holdco	0.31	0.39	0.50	0.69	0.83	0.95
<i>Transmission Guidance</i>		<i>0.40</i>	<i>0.50</i>	<i>0.66-0.69</i>	<i>0.77-0.83</i>	<i>0.87-0.96</i>
AEP River	0.10	0.06	-	-	-	-
GenCo	0.50	0.51	0.17	0.18	0.22	0.06
Corp & Other	0.22	(0.13)	(0.10)	(0.08)	(0.10)	(0.10)
Consolidated EPS	\$3.43	\$3.69	\$3.70	\$3.85	\$4.10	\$4.10
<i>Prior Estimates</i>	<i>\$3.43</i>	<i>\$3.69</i>	<i>\$3.70</i>	<i>\$3.84</i>	<i>\$4.06</i>	<i>\$4.09</i>
<i>Consensus</i>			<i>\$3.66</i>	<i>\$3.83</i>	<i>\$4.08</i>	<i>\$4.22</i>
<i>Guidance EPS: 4%-6% CAGR 2014Adj.- 2018E (\$3.30 Starting Point)</i>					<i>UBSe</i>	<i>4.5%</i>
<i>Guidance</i>		<i>\$3.60-\$3.80</i>				

Source: Company Filings, FactSet, and UBS Estimates

Valuation: Increase Price Target \$5 to \$77

Our valuation is based on a 2018E sum-of-the-parts analysis. With most of its ratecases completed and a significant improvement in earned ROEs for KY and WV expected for 2016, we continue to apply a 5% premium to the average 2018E peer P/E multiple to the utilities. We continue to value the merchant GenCo at a 7x EV / EBITDA multiple. The regulated peer multiple has expanded to ~17.8x from ~16.7x since our last MtM, driving the majority of the increased valuation.

Figure 78: AEP Sum-of-the-Parts Valuation

American Electric Power		UBS						
Sum-of-the-Parts Analysis		2018E EPS	P/E & EV/EBITDA Multiples				Scenarios	
Utilities:	EPS	Low	Base	Premium	High	Low	Base	High
Vertically Integrated Utilities	\$3.14	15.8x	17.8x	5%	18.8x	\$ 25,907	\$ 29,187	\$ 29,359
Transmission Utilities	\$0.83	16.8x	18.8x	0%	19.8x	\$ 6,966	\$ 7,795	\$ 8,210
Parent & Other	-\$0.10	16.8x	17.8x	5%	18.8x	\$ (877)	\$ (929)	\$ (935)
Total Regulated Equity Value	<u>\$3.88</u>	16.6x	18.7x	5%	19.0x	\$ 31,996	\$ 36,052	\$ 36,633
Value/sh						\$ 64.42	\$ 72.59	\$ 73.76
Genco Valuation	EBITDA	Low	Base	(Discount)	High	Low	Base	High
Ohio Coal Assets (open EBITDA)	\$73	5.0x	7.0x	0%	8.0x	\$ 363	\$ 509	\$ 581
"Non-PPA" Assets (open EBITDA)	\$326	5.0x	7.0x	0%	8.0x	\$ 1,629	\$ 2,281	\$ 2,606
Less: Net Debt						\$ (826)	\$ (826)	\$ (826)
Total GenCo Equity Value						\$ 1,166	\$ 1,963	\$ 2,362
Value/sh						\$ 2.35	\$ 3.95	\$ 4.76
Fleet Sale Impacts:								
Base Case:								
Plus: Accretion from sale of Ohio coal assets (<u>share repo</u>)							\$ 0.01	
Plus: Accretion from sale of non-PPA assets (<u>share repo</u>)							\$ 0.17	
High Case:								
Plus: Accretion from re-ratebasing of Ohio Coal assets (<u>same incremental value as the PPA</u>)								\$ 2.22
Plus: Accretion from sale of non-PPA assets only (<u>reinvest in transmission</u>)								\$ 3.35
Shares Outstanding (2018E)						497	497	497
Total Value per Share						\$67.00	\$77.00	\$84.00
Upside/(Downside)						-4%	10%	20%

Source: Company filings, FactSet, UBS estimates

Avista Corp.

Avista is currently trading at ~20x 2018E, a 2x-turn premium to even SMid peers and is the second most expensive utility we track (MGE Energy trades at 22x) and we continue to believe there are more attractive return opportunities elsewhere given the approximately average 4-5% EPS growth target.

We forecast 2Q16 adjusted EPS of **\$0.46** vs \$0.40 in 2Q15 and \$0.43 Consensus.

No contribution from the ERM was recognized in 2Q15.

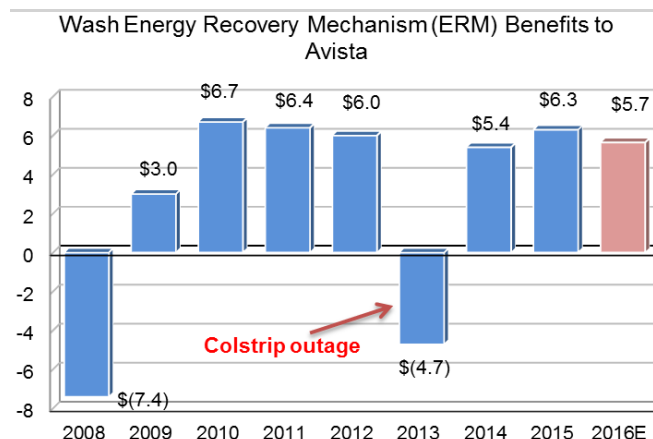
- **Key Drivers:** The 2015 Washington rate case drives the majority of the earnings improvement but this is offset by meaningful regulatory lag even with a slower rate of capex in 2016 compared with 2015A.
- **Wildcard Factors:** (1) On the 1Q16 call management revised its 2016E Energy Recovery Mechanism [ERM] expectations to be in 75%/25% sharing band [\$4M-\$10M of pretax benefits before sharing] vs. prior expectation of being "within the \$4M benefit deadband; and (2) magnitude of volume growth with Avista being one of dwindling group of utilities expecting customer/load growth to be a noticeable positive factor [~1%]

Figure 79: AVA 2Q16E Earnings Walk

Avista Corp 2Q16 Earnings Walk	EPS
2Q15A Adjusted EPS	\$0.40
Weather vs Normal in 2Q15	\$0.00
Weather vs Normal in 2Q16	\$0.00
Sales Benefit	\$0.02
ERM Impact	\$0.02
Rate Relief	\$0.08
AERC	\$0.00
O&M	(\$0.02)
D&A	(\$0.04)
Interest	(\$0.01)
Dilution	\$0.00
Other	\$0.00
2Q16E Adjusted EPS	\$0.46
2Q16 Consensus	\$0.43
2016 UBSe EPS	\$2.06
2016 Consensus	\$2.04
2016 Guidance	\$1.96-\$2.16

Source: Company Filings, FactSet, and UBS Estimates

Figure 80:



Source: Company Filings and UBS Estimates

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

[5/4/16 Improved Hydro Expectations](#)

[3/18/16 Expecting Some Runoff \(d/g to Sell\)](#)

[2/26/16 Aiming for a Longer Rateplan](#)

[2/23/16 Searching for Clues in Utility M&A](#)

[8/7/15 Steady Progress on Ratecases](#)

What are the key updates for AVA?

We examine the latest rate case developments

- **Washington:** The current multi-year electric and gas rate cases were filed in February with a 9.9% ROE on 48.5% equity. Under the plan, AVA is requesting new rates on January 1, 2017 (\$38.6M elec and \$4.4M gas) followed by a second step-up in 2018 (\$10.3M elec and \$0.9M gas), with a rate increase stayout stipulating no new rate filing for rates effective prior to July 1, 2018. A settlement conference was held earlier this month and another one is set for the end of August, following intervenor and Commission Staff testimony due by August 17th. The Attorney General's Office of Public Counsel is appealing (Court of Appeals) the attrition in the previous 2015 rate case and we believe it would be unusual for them to settle in the current rate case on that issue in the interim. In the past AVA has been able to reach settlements with other parties and a partial settlement is always a possibility.
- **Idaho:** The case requesting a +\$15Mn revenue increase (9.9% ROE) was just filed on May 26th and testimony is not expected until October 2016.
- **Oregon:** Management expects to file its next natural gas rate case in 2H16 given the magnitude of capital spending in the jurisdiction. The previous rate case (D-UG 288) was fully litigated and a +\$4.5Mn revenue increase was authorized earlier this year with a 9.4% ROE which included a decoupling mechanism.
- **Alaska:** Avista has continually stated since it purchased Alaska Electric Light & Power Company (AEL&P) that it was evaluating a rate case and it finally appears that management is approaching a filing with the catalyst being the investment in a diesel generator later this year. The last rate case was fully litigated in 2011 with a +\$7Mn revenue increase based on a 12.88% ROE and 54% equity ratio.

A settlement without Public Counsel and/or a partial settlement are always possibilities.

A multi-year case could help reduce regulatory lag that has perpetually reduced earnings.

Rate cases are possible in the next approximate six-month window for Oregon and Alaska.

Figure 81: Avista Rate Case Status

Avista Rate Case Status							
State	Service	Filing Date	Request (\$Mn)	ROE (%)	Equity (%)	Timeline	Case #
Idaho	Electric	5/26/2016	\$15.4	9.9%	50.0%	October (Testimony & Settlement Conference)	C-AVU-E-16-03
Washington	Electric	2/19/2016	\$48.9	9.9%	48.5%	August (Testimony & Settlement Conference)	D-UE-160228
Washington	Gas	2/19/2016	\$5.3	9.9%	48.5%	August (Testimony & Settlement Conference)	D-UG-160229
Oregon	Gas	Management is evaluating the need for a rate case filing; guided to 2H16 filing					
Alaska	Electric	Management is evaluating the need for a rate case filing; potential around YE16 based on investment timing					

Source: SNL

- **Alaskan opportunities slower to develop in the new oil price environment:** We look for details on the call if there are any updates on the Juneau LDC as management continues to evaluate the potential in the lower priced oil environment. If Avista ultimately moves forward with this endeavour management indicated that it could represent a potential \$130Mn opportunity Separately Salix was selected as a finalist in the Alaska Industrial Development and Export Authority (AIDEA) RFP to develop an LNG plant but AIDEA still needs to grant final approval. For both Salix and the LDC opportunity, Avista is evaluating what kind of regulatory mechanisms are available to make the conversions more affordable and potential alternatives.
- **Colstrip settlement achieved:** Avista and the other joint owners reached a proposed settlement to release liability and lead to retirement of Units 1 & 2

AVA owns 15% of Units 3/4 & 4.

by 2022 with the dismissal of Units 3 & 4 claims. The question remains what the precise coal ash liabilities will be associated with the plant.

EPS estimates slightly adjusted

In 1Q16 management issued \$27Mn of equity and still intends to issue an additional \$28Mn during the balance of the year. The 1Q16 equity issuance was a contributing factor in the equity ratio increasing to 48.1% as of March 31st compared with 46.9% as of year-end 2015. \$155Mn of long-term debt is also expected to be issued during the year, in part to refinance a \$90Mn debt maturity for this year. There are no maturities in 2017 but \$273Mn comes due in 2018.

Figure 82: AVA EPS Estimates

Avista EPS Estimates	2015A	2016E	2017E	2018E	2019E
Segment EPS					
Avista Utilities (WA, ID, OR)	\$1.81	\$1.98	\$2.05	\$2.13	\$2.24
AEL&P Utility (AK)	\$0.11	\$0.11	\$0.11	\$0.12	\$0.13
Other	(\$0.03)	(\$0.03)	(\$0.03)	(\$0.03)	(\$0.03)
UBS Estimates	\$1.89	\$2.06	\$2.13	\$2.23	\$2.33
Prior UBS estimate	\$1.89	\$2.06	\$2.13	\$2.22	\$2.33
Consensus		\$2.05	\$2.13	\$2.22	\$2.32
Guidance		\$1.96-\$2.16			
Guidance EPS: 4-5% LT CAGR				UBSe 4.3%	
Earned ROE (8.6%-9.2%, w/ 60-70 bps lag)		8.9%	8.9%	8.9%	8.9%

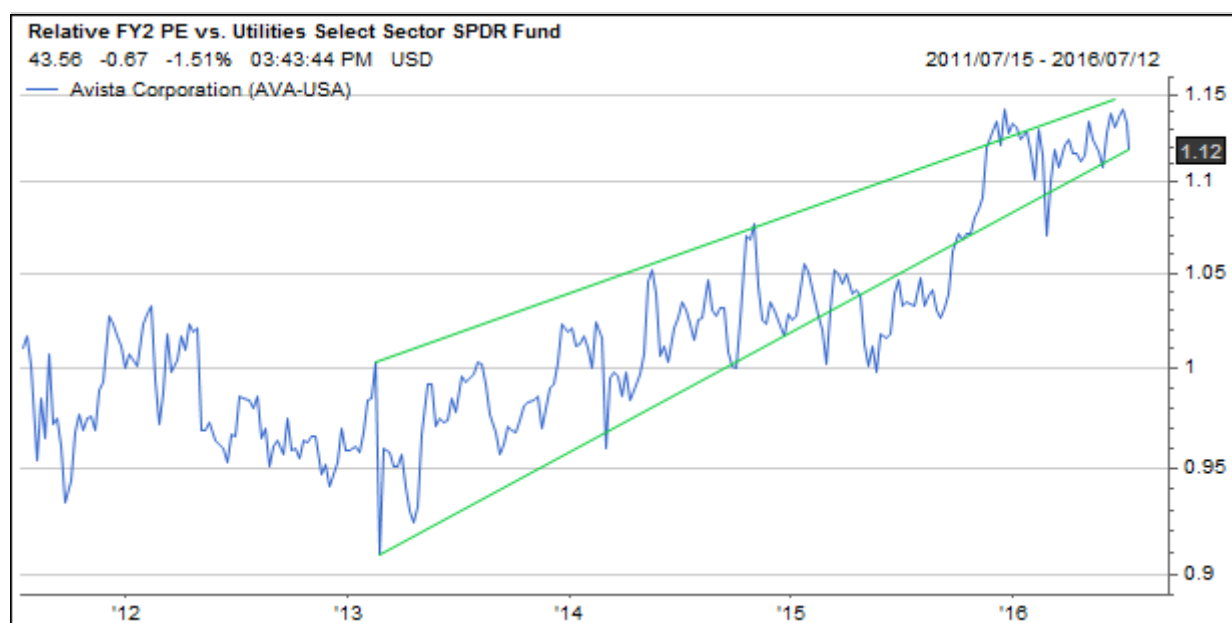
Source: Company Filings, FactSet, and UBS Estimates

Valuation: Increase Price Target \$3 to \$39

Our valuation remains based on a 2018E peer utility P/E with an in-line multiple. Avista is currently trading at ~20x 2018E, a 2x-turn premium to even SMid peers and is the second most expensive utility we track (MGE Energy trades at 22x) and we continue to believe there are more attractive return opportunities elsewhere given the approximately average 4-5% EPS growth target.

The 12% premium to peers compared with an approximately average multiple during 2013-1H2015.

Figure 83: AVA Relative FY2 PE Multiple



Source: FactSet

Figure 84: AVA P/E Valuation

Avista P/E Valuation (2018E)		Low Case		Base Case		High Case	
		Multiple	\$Mn	Multiple	\$Mn	Multiple	\$Mn
				Peer	17.7 x		
Consolidated Net Income	\$146	15.2 x	\$2,219	17.7 x	\$2,583	20.2 x	\$2,948
Fully Diluted Outstanding Shares (2018E)			65.6		65.6		65.6
AVA Equity Value per Share			\$34.00		\$39.00		\$45.00

Source: Company filings, FactSet, UBS estimates

Calpine Corporation

2Q expectations should be ahead; it's a quiet story for now

We forecast Calpine reporting 2Q16 adjusted EBITDA of **\$443Mn**, better than the Street at \$401 Mn. Aggregate hedge positions appear to suggest flat to some degradation in YoY results, coupled with a reduction in expected dispatch given improvement in Western hydrology (2Q is a big run-off quarter likely pressuring volumes by at least 2-3TWhs). See the charts below on improving conditions. We suspect conditions were aided in 2Q to continued substantial switching albeit off YoY. In its latest quarter owned by Calpine, we estimate that Granite Ridge contributed ~\$10Mn at best given continued mild Northeast conditions.

Decent quarter ahead

Figure 85: CPN 2Q16 Adj EBITDA Walk

Calpine Corp 2Q16 EBITDA Walk		
2Q15A Adjusted EBITDA	\$457	Notes
Capacity Price Changes		
RA Payments (California)	-	
Non-California (PJM, etc.)	(5)	PJM Rolloff YoY, improvement in June
Energy Margin		
Geysers Outage	-	Geyser Deductibles Incurred, so insurance will roughly offset
Hedge Position	(5)	Open hedges declining substantially (except for PJM West)
Garrison CC	5	Full Quarter Contribution
Granite Ridge	10	Acquisition closed 2/5/2016
Total Uplift	10	
Volumetric Improvement	(30)	Well Diversified Provided a Normal Quarter/ Hydro Pressures in West
Net Change	(14)	
2Q16A Adjusted EBITDA	443	
2Q16A Adjusted EBITDA Consensus	\$401	
2016 UBSe EBITDA	1,915	
2016 Consensus	1,874	
2016 Guidance	\$1,800-\$1,950	

Source: Company reports, ThomsonReuters, UBS estimates

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

[5/2/16: Successfully Navigating A Warm Winter](#)

[2/16/2016: Preparing for a Gradual Debt Paydown](#)

[2/12/2016: Pausing on Buybacks](#)

[11/2/2015: Reaching the Trough](#)

What does 2017 Guidance Look Like?

We include our initial cut of a YoY walk on the guidance factors driving 2017 to be a positive YoY guide vs. 2016. We note a partial year of the York II CCGT in PJM drives the bulk of the delta. Further, we note the Granite Ridge is a partial contributor as well. We see a range of \$1.95-2.15 Bn as likely, with a \$200 Mn band. We suspect Street consensus EBITDA of just north of \$2 Bn is appropriate in the context of the new assets, higher capacity payments, and further CCGT expansions. We suspect further expansion of retail efforts could yet drive upside.

With expectations on guidance typically becoming a defining 3Q event for shares, we include our walk in an effort to address this concern.

Figure 86: 2017 vs. 2016 YoY Walk on FY Adj EBITDA Guidance

2016 EBITDA Estimate	\$1,913	
Revenue Type Walk	Items	Notes
Total (PJM. etc)	31	Step-up in PJM Capacity Rev's
York II/Expansion CCGT (Summer '17)	52	June, 2017 In-Service (Partial Year)
York Toll Expansion		Close to ~Market Prices
Granite Ridge (Partial Year)	6	February, 2016 Acquisition
Hedges	32	Delta -\$3/MMWh on Open Volumes
2017 EBITDA Estimate	2,034	
UBSs Expected Guidance Range	1950-2150	
UBSe Point Estimate	2,036	
Consensus	2029	

Source: Company reports, ThomsonReuters, UBS estimates

What about the hedges?

Calculating the precise YoY shift in hedge value is among the biggest deltas in our assumptions above. We see appropriate estimation of the rolloff of this hedge profile as critical in deriving the trend; we note while opaque in its precise calculation, it would appear as if hedges skew slightly positive in energy margins.

Figure 87: Hedge Value and Open Market Comparison

Hedging	2016		2017		2018	
	\$/MWh	Percent	\$/MWh	Percent	\$/MWh	Percent
1Q16	\$18	86%	\$24	48%	\$32	28%
4Q15	\$19	80%	\$27	38%	\$34	25%
3Q15	\$16	63%	\$27	27%	\$32	19%

Source: Company reports and UBS estimates

What are the key updates for CPN?

- **South Point: Sold For A 'Not So Hot' Price:** We flag the South Point price is nominally low, but has many adjusting factors which make it a more relatively equivalent price to other asset sales. We note we had already assumed a low valuation given the contract is among the few uncontracted plants in a regulated market.

Prices appear quite low, but are principally due to high operating costs and poor location.

Adjusting for incremental factors lands more comparable prices

Figure 88: Estimated Breakdown of Economics

Southpoint Sale in Nevada (\$ Mn)	\$/kW Equiv on 520 MWs
75.6 Purchase Price (received by CPN)	145
3.6 Integration Costs	7
<u>20.8</u> Required Investment	40
100 Subtotal	192
<u>112</u> NPV of Transmission	215
212 Grand Total for NV Energy	408

Source: Company disclosures and UBS estimates

The plant is located not just in the regulated Southwest market, but also is not near a load pocket and sells into the expensive WAPA transmission system (akin to Sutter selling into Smud, outside of CAISO in California). The transmission described above is a ~\$10 Mn/yr payment for 25-years to ensure the plant is deliverable. Further, it suffers from higher property taxes, natural gas taxes and higher operating costs due to Native American tribal lease. Lastly, there is a legacy steam turbine issue that has not been fixed (~hence the \$21 Mn in costs above) to ensure the plant is back to its full capacity.

RFPs in Arizona: Don't Expect Much Either

For other plants seeking to participate in the ongoing PNW All-Source RFP we don't see a silver lining here either as generators are keen to participate in this 400-600 MW procurement (for 2020). Given the summer-only needs we suspect pricing will be quite low, designed to entice peakers to participate. We suspect PNW may well move to acquire into ratebase any plant ultimately participating in this process, albeit don't expect any details until at least December when bids are due. Lastly, given the willingness to evaluate storage + solar solutions, the RFP would well have further pressure on prices as gas assets must ensure they are competitive vs. solar resources, which benefit from the ITC.

Looking the Other Southwest assets: Prospects tied to RFPs still

Interest in the region has grown of late following a recent debt deal for the Starwest portfolio. We emphasize the Arlington Valley asset for this portfolio sits near Harquahala and other CCGTs in the 'power' corridor previously to California. We suspect prospects for getting contracted remain principally tied to Salt River Project or APS – and look for developments. In contrast, the Griffith plant near the NV border appears more tied to prospects with NV Energy (as well as nascent efforts for restructuring for larger commercial entities appears a further angle as well, albeit for smaller slices).

While likely the best deal possible for shareholders given the disadvantages, we suspect Western power plant datapoints will remain distresses as buyers are well aware of the issues. We emphasize regional price points could yet head lower as renewables continue to cloud the fundamental need for these assets coupled with increasing uncertainty as merchant plants generate negative FCF stand-alone.

- **Calpine: More Divestment? Looking at Track record:** Calpine's largest non-core sale was its 3.5GW divestiture of its Southeast Portfolio for \$1.57Bn (\$1.53Bn cash proceeds) in April 2014. Below we show other non-core asset sales executed by management since 2010 and although different markets are not ideal for comparisons, the clear trend is that pricing has declined in these regulated markets.

We suspect among the next asset focuses will be Hermiston in Oregon given the upcoming RFP for new generation in the state. The question is whether an additional brownfield expansion for POR will be more economic than buying the uncontracted plant in the state. We suspect both historic terms on offer to contract the plant or sell the plant have proved unpalatable.

Figure 89: Calpine Non-Core Asset Sales: South Point is UBSe

Assets	Date	Region	Capacity	Sale Price	\$/kW Value
South Point Energy Center	Apr-16	AZ	520	76	\$145.4
Osprey Energy Center	Jan-15	FL	600	166	\$276.7
Oneta, Decatur, etc.	Apr-14	South East	3,498	1,570	\$448.8
Broad River	Nov-12	SC	847	427	\$504.1
Riverside Energy Center	May-12	WI	600	402	\$670.0
Rocky Mountain & Blue Spruce	Apr-10	CO	931	739	\$793.8

South Point sets a new low bar

Source: SNL Energy, Company Filings, and UBS Estimates

Issues to Address on the Call

- **What about the West Portfolio Value?:** The underlying question amidst the latest sale in NV as well as any likely low print in the state for DYN's own Moss 1&2 print (we acknowledge this is *below* that of CPN's assets given unattractive location) is what is Calpine's Western portfolio worth?
- **Metcalf Energy Center is probably next asset to focus on?** We emphasize the Metcalf Energy Center (South of the Bay Area) is the latest completely unhedged CCGT for Calpine in California. We tweak down our expectations here from \$250/kW to \$200/kW. We note this is distinctly different from peers as the unit was in recent years contracted under a lucrative local resource adequacy (eg- *constrained*) capacity payment. We see upside to the plant even if only partially contracted. The plant is located near the pivotal Metcalf transmission station at which there appears a power bottleneck per CAISO.
- **Further retail acquisitions: with a Northeast focus?** Following the success of Champion, we would not be surprised to see management further expanding into the Northeast to complement its assets. Calpine recently expanded its Champion retail effort into neighboring Maine and Connecticut and stated it would like to further grow the retail footprint. This remains part of a wider industry effort we have seen of late. Among companies with known divestments ongoing is ConEd Solutions. Both PSEG and Calpine have indicated an interest in scaling their business.

Revisiting Capital Allocation

Management highlighted the callable 2023 first lien secured notes with a book yield of 7.88% (current yield 7.4%) as offering an opportunity since it is the most expensive piece of long-term debt in the structure. \$120Mn of the debt can be called in December at 103 with the balance able to be called in January 2017. Another area discussed was refinancing the 2019 and 2020 first lien term loans.

Calpine's debt has appreciated lately and is now trading above par. For example the 2025 senior notes were trading in the 85-90 range in February and have increased sharply to above par.

Recovery in Calpine's bond pricing reduces the return profile of repurchasing debt below par but also reduces the pro-forma interest expense on new issuances.

Figure 90: Updated Calpine Long-Term Debt

As of 3/31/16 (Except Current Yield)	Maturity (yr)	Book Yield	Current Yield	2015	2016	2017	2018	2019	2020+	Current Price
Calpine Corp.										
2023 Senior Notes		5.38%	5.32%						1,235	101
2024 Senior Notes		5.50%	5.45%						642	101
2025 Senior Notes		5.75%	5.72%						1,531	101
First Lien Term Loan		4.30%	5.86%				-			
2019 First Lien Term Loan		4.40%	5.86%					794		
2020 First Lien Term Loan		4.30%	5.86%						377	
2022 First Lien Term Loan		3.75%	5.86%		16	16	16	16	1,505	
2023 First Lien Term Loan		4.00%	5.86%		6	6	6	6	510	
2022 First Lien Secured Notes		6.00%	5.69%						738	105
2023 First Lien Secured Notes		7.88%	7.39%						568	107
2024 First Lien Secured Notes		5.88%	5.56%						484	106
Total Calpine Corp.		8,469		-	21	21	21	815	7,590	
Total Maturities		8,469		-	21	21	21	815	7,590	
Book Interest Expense (Consolidated)		\$438		Book Interest Expense (Ex-GenCo)				\$438		
MtM Interest Expense (Consolidated)		\$491		MtM Interest Expense (Ex-GenCo)				\$491		
Delta (%)		-11%		Delta (%)				-11%		
2018E EBITDA (UBSe)		\$2,262		2018E EBITDA (UBSe)				\$2,262		
Delta (%)		-2%		Delta (%)				-2%		
2018E FCF (UBSe)		\$1,115		2018E FCF (UBSe)				\$1,115		
Delta (%)		-5%		Delta (%)				-5%		

Source: Company Filings, FactSet, and UBS Estimates. * Current Yield as of April 29, 2016

Building liquidity once more

Following the Granite Ridge and Champion acquisitions management stated a priority is "rebuilding liquidity". CPN is targeting 4.5x net debt / adjusted EBITDA and net debt as of 3/31/16 increased to \$11.57Bn from \$10.93Bn at YE15 as CPN purchased Granite Ridge for \$527Mn.

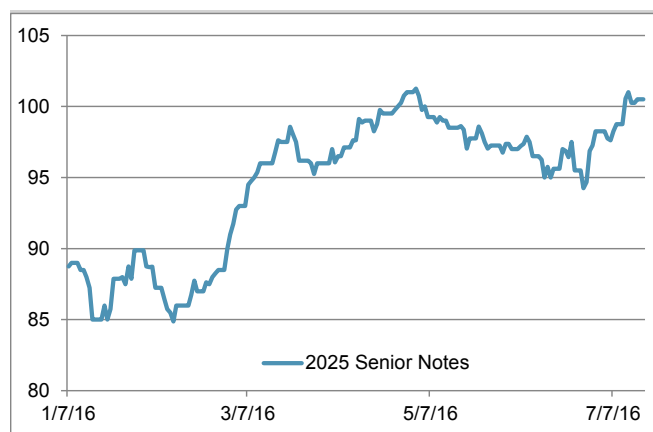
As expected there were no repurchases executed in the quarter and ~\$70Mn debt amortization was consistent with 1Q15. We would not expect any (or at least not meaningful) buybacks in the 2Q period (or even through the conference call). Rather, the key question on capital allocation will remain plans in 2H as cash builds once more from recent acquisitions.

Figure 91: Calpine Capital Allocation Analysis

Calpine Capital Allocation Analysis		2016E
CPN Definition of Capital for Allocation		
12/31/15 Unrestricted Cash		906
Plus: 2016E FCF Generated (Midpoint)		783
Plus: 2017E Proceeds from Osprey Sale		166
Plus: 2017E Proceeds from South Point Sale		76
Less: Minimum Cash balance		(100)
Total Capital Available for Allocation		1,830
Less: Growth Capex		
Granite Ridge Purchase		(527)
York 2 and Others		(285)
Total Growth Capex		(812)
Less: Debt Reduction		
Required Mandatory Debt Amortization		(210)
Committed Debt Paydown		(225)
Total Debt Reduction		(435)
Net Capital Available Remaining		583
Implied Year-End Cash Balance		(1,247)
Management Liquidity Target		\$1,000
Revolver Capacity		\$1,542

Source: Company Filings and UBS Estimates

Figure 92: Calpine 2025 Senior Note Pricing



Source: FactSet

Latest EBITDA Estimates

We include our latest segment level EBITDA estimates for the company, continuing to show a nice step-up in our 2017+ EBITDA estimates principally on the back of higher capacity prices across PJM and New England as well as from new assets reaching in-service. We emphasize 2017 expectations will become the key focus for shares *after* 2Q results as mgmt has had several years of more challenging EBITDA guidance vs. Consensus. We emphasize our estimates reflect the recent rally in forward sparks as well as reduced capacity factor assumptions for the Western portfolio amidst a ramp in capacity factor (%).

Figure 93: CPN estimates

Calpine Adj. EBITDA UBSe	2015	2016	2017	2018	2019	2020
West	745	610	600	606	522	516
Texas	411	438	532	594	558	530
Southeast	-	50	47	46	46	45
North	742	629	654	792	698	656
Other	30	33	35	35	36	37
Corporate Allocation	48	153	167	170	172	175
Total EBITDA	1,976	1,913	2,036	2,244	2,033	1,958
Guidance	1965-2000 1800-1950					
Street Consensus	1,991	1,918	2,059			
UBS Previous	1,976	1,915	2,163	2,262	2,033	1,955
EBITDA Change %	0.0%	0.1%	6.3%	0.8%	0.0%	-0.2%
EBITDA Change \$	\$0	-\$1	-\$128	-\$18	\$0	\$3

Source: Company reports, ThomsonReuters, UBS estimates

Valuation: Maintain price target at \$17/sh

We are maintaining our price target at \$17/sh with little change in our 2017 EBITDA estimates. We continue to see shares as trading principally as a function of the credit cycle in high-yield energy given its higher leverage. We reflect both the actual sale price of South Point and updated EBITDA estimates.

Figure 94: Calpine SOP Valuation: Sticking with our \$17 PT on refresh

All figures in US \$ million except per share data							
	2018E EBITDAR	EV/EBITDA Multiple			Enterprise Value		
		Low	Base	High	Low	Base	High
West	606	5.0x	6.0x	7.0x	\$3,032	\$3,639	\$4,245
Texas	594	6.0x	7.0x	8.0x	3,565	4,159	4,753
Southeast (Remaining)	46	6.0x	7.0x	8.0x	278	324	370
North	792	6.0x	7.0x	8.0x	4,750	5,542	6,334
Other	35	6.0x	7.0x	8.0x	212	247	282
Hedge Impact (Adj. for Steam, etc.)	(181)	6.0x	7.0x	8.0x	(1,085)	(1,265)	(1,446)
Champion Energy	63	4.0x	5.0x	6.0x	250	313	375
Adj. for Commodity Margin to EBITDA	170	6.0x	7.0x	8.0x	1,018	1,188	1,358
Total / Implied	2,125	5.7x	6.7x	7.7x	\$12,021	\$14,146	\$16,272
Subtract: Net Debt						(11,309)	
Subtract: Operating Leases						(190)	
Add: NPV of NOLs						1,171	
Add: Hedge Value						517	
Add in Further Plant-Level Value	MWs	\$/kW			Low	Base	High
Remaining Southeast Portfolio:		Low	Base	High			
Auburndale Peaking Energy Center (FL)	117	\$100	\$200	\$300	\$12	\$23	\$35
Osprey Energy Center (FL) - 4Q16 Close	599		\$277		166	166	166
Pine Bluff Energy Center (AR)	215	\$150	\$250	\$350	32	54	75
Morgan Energy Center (AL)	807	\$150	\$250	\$350	121	202	282
Total / Implied	1,738				\$331	\$445	\$559
Subtracting out EV/EBITDA-based Value					(278)	(324)	(370)
True 'Merchant' West Portfolio:							
Metcalf (CA) - Local RA Eligible	605	\$100	\$200	\$300	61	121	182
Hermiston (OR) - RFP Opportunity?	635	\$150	\$250	\$350	95	159	222
South Point (AZ) - 4Q16 Close	520		\$145		76	76	76
Total	1,760				\$231	\$355	\$479
Subtracting out EV/EBITDA-based Value	36				(182)	(218)	(254)
NPV of Equity					\$2,313	\$4,593	\$6,874
Projected Number of Shares Outstanding (2018E)					276	276	276
Equity value per share					\$8.00	\$17.00	\$25.00

Source: Company reports, UBS estimates

Latest FCF Outlook

We include our latest FCF projections, with our 2016 estimate sitting squarely near the midpoint of the range through our latest MtM. The question remains just how much debt will be paid down relative to shares bought back, particularly following management's latest commentary suggesting it should have been clearer on debt paydown ambitions through the latest downturn

Figure 95: Our latest FCF projections

Calpine FCF Analysis (UBSe)	2014	2015E	2016E	2017E	2018E	2019E
UBS FCF Est. (\$Mn)	830	671	744	861	1,050	823
~\$250 Mn uplift ex-Hedges from 2016-2018						
Management FCF Guidance (\$Mn)	800-850	825-860	710-860			
FCF per Share (using Avg)	2.03	1.73	2.09	2.62	3.58	3.19
Management FCF/Share Guidance	\$1.85 - \$2.10	\$2.25-2.35	\$2.00-2.40			
FCF Growth (YoY)	32%	-15%	21%	25%	37%	-11%
CAGR off 2011 of \$1.01 FCF/shr	26.1%	14.5%	15.7%	17.2%	19.8%	15.5%
FCF Yield	18.8%	15.2%	16.9%	19.5%	23.8%	18.7%
Turbine Upgrade	(20)	0	0	0	0	0
Deer Park, TX (CT Addition)	(34)	0	0	0	0	0
Channel, TX (CT Addition)	(34)	0	0	0	0	0
Garrison, DE (New PJM CCGT)	(48)	0	0	0	0	0
York CCGT (New PJM CCGT)	0	(133)	(285)	(265)	0	0
Other Growth (Mankato, etc)		(223)	0			
Growth Capex	(136)	(355)	(285)	(265)	0	0
Growth & Acquisition Financing		(240)	(500)	Granite Ridge		
Projected Debt Amort/Sw eeps	(320)	(460)	(435)	(200)	(200)	(210)
Remaining FCF	374	(161)	(476)	396	850	613
Asset Sales	1,573	0	0	0	0	0
Starting Cash	941	717	906	906	906	906
Ending Cash	717	906	906	906	906	906
Δ in Cash Balance	(224)	189	(0)	-	0	-
Deployable for Growth/Share Rep	2,171	(350)	(476)	396	850	613
Share Repurchase Placeholder	(1,100)	(529)	(250)	(500)	(500)	(500)
Projected Shares YE O/S	409	365	347	311	276	240

Source: Company reports, UBS estimates

CMS Energy Corporation

The prospects of new energy legislation in Michigan appears off-the-table in the near-term following the June recess. The challenge for 2017 will be educating new Representatives after the election cycle this Fall. Despite this setback, CMS has continued to outperform and still trades at a 10% premium, among the highest in the group due to management's track record of delivering on its above-average EPS growth rate in different cycles. We continue to see CMS as among the best positioned to maintain an above-average EPS growth rate, seeing valuation as our principle concern.

We forecast 2Q16 adjusted EPS of **\$0.33** vs \$0.25 in 2Q15 and \$0.29 Consensus.

- **Key Drivers:** The 2015 electric and gas rate cases continue to be the primary drivers of earnings improvement in 2016. In 1Q16 there was +\$0.13 improvement (+\$0.10 electric and +\$0.03 gas) but the revenue increase should decline QoQ due primarily to the ~\$40Mn rate reduction agreed to for mid-April 2016 around the 'classic seven' coal retirements.
- **Wildcard Factors:** (1) Magnitude of O&M saving efforts with management announcing an incremental +\$0.13 cost reduction plan in 1Q16 to offset mild winter weather. 2Q16 weather appears largely consistent with the historical average and CMS has commented that there is further flexibility on maintenance and other spending to help the company to achieve its FY16 EPS guidance.

CMS discussed levers it can pull to offset the challenging 1Q16 weather, above the typical rate reduction efforts the company strives to achieve.

Figure 96: CMS 2Q16E Earnings Walk

CMS Energy 2Q16 Earnings Walk	EPS
2Q15A Adjusted EPS	\$0.25
Utilities	
Weather	
Weather vs Normal in 2Q15 Near Normal	\$0.02
Weather vs Normal in 2Q16 Near Normal	\$0.01
Revenues	
2015 Electric Case: \$165Mn December 2015	\$0.04
2015 Gas Case: \$40Mn January 2016	\$0.01
2016 Electric Case: \$225Mn w ./ \$38Mn for '17	\$0.00
O&M	
Lower O&M: Attrition, smart meters, etc.	\$0.02
Lower Pension costs and other savings	\$0.03
DIG Maintenance Outage: Fall 2015 -\$8Mn	\$0.00
Interest Expense	\$0.00
Investment Costs: D&A, Property Taxes, etc.	(\$0.06)
Enterprise	\$0.01
Interest and Other	\$0.00
Dilution	\$0.00
2Q16E Adjusted EPS	\$0.33
2Q16 Consensus	\$0.29
2016 UBSe EPS	\$2.02
2016 Consensus	\$2.02
2016 Guidance	\$1.99-\$2.02

Source: Company Filings, FactSet, and UBS Estimates

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

[5/3/16 In-Line with Plan](#)

[2/10/16 Leaning Into Their Bonus](#)

[10/30/15 Delivering on Plan](#)

[10/26/15 Tapping the Brakes](#)

[10/26/15 Positioning the Quality Premium for Regulated Utilities](#)

[7/24/15 Gain with No Pain](#)

What are the key updates for CMS?

- **Resetting expectations for MI legislation:** The Michigan state legislature entered their summer recess in early June without holding a vote on the energy legislation. When the bill was up for debate media reports indicated that there were multiple aspects of the potential legislation being debated such as the ultimate terms for consumer choice/switching and renewables mandate/goal. Importantly, Senate Energy and Technology Committee Chair Senator Mike Nofs (R) will remain in the legislation and continue to advocate for legislation. The challenge for next year will be that there is expected to be an education period for any new Representatives which could make the process more challenging.
- **Multi-year electric rate case takes the stage this summer with Staff testimony in late July:** CMS filed its latest electric ratecase on March 1st \$225Mn over a three year period (2017-2019) based on a 10.7% ROE. The majority of the request is to recover for capital investments (\$161Mn, 72%) and \$17Mn relates to lower peak customer delivery sales. The delta between the 10.7% ROE request and the 10.3% authorized is \$25Mn. PSC Staff testimony is scheduled to be filed on July 22nd with rebuttal testimony by August 26th. Hearings are scheduled to take place beginning September 7th with a Proposed Decision expected by December 16th. (Docket C-U-17990)

Separately CMS expects to file its next gas rate case in the near future where management continues to advocate for more tracker-like mechanisms to reduce the need for perpetual rate cases to recovery spending.

- **Palisades update still to be determined:** We continue to look for updates from Entergy who owns and operates the Palisades nuclear plant which is contracted with CMS' Consumers. Entergy management has continued express its desire to become more regulated and this would be another step down that road. Given the above-market contract, we believe there could be an opportunity for a mutually-beneficial outcome for all parties.
- **New Independent added to the PSC:** On July 6th Michigan Governor Rick Snyder appointed Rachael Eubanks (I) to the Michigan Public Service Commission to serve the remainder of John Quackenbush's term through July 2017. The appointment is still subject to Senate confirmation.

The question is how much turnover will occur in the House – if there are significantly more new Representatives this lack of continuity could make the process more challenging in 2017.

EPS estimates unchanged

We are maintaining our EPS estimates through 2019 are unchanged and remain largely in line with consensus. As mentioned 1Q16 weather creates a headwind but management has conservatively established a 'reinvestment' contingency. With -\$0.31 of "investment costs" in the guidance for 2016, we note that a portion of this is opportunistic (some maintenance work, tree trimming, donations, etc.) that could be reduced if needed or increased if possible. Bottom line is that CMS seems highly confident in its 6%-8% long-term EPS growth rate. For example CMS raised its 2016E guidance on February 4th when it reported FY15 earnings which incorporated preliminary mild weather data for the winter.

We are maintaining our estimates at 7% annual earnings growth (midpoint of the recently updated 2017+ 6-8% target) through 2017

Figure 97: CMS EPS Estimates (2014A-2019E)

CMS EPS Breakdown	2014A	2015A	2016E	2017E	2018E	2019E
Consumers Electric	\$1.40	\$1.43	\$1.41	\$1.50	\$1.59	\$1.68
Consumers Gas	\$0.65	\$0.69	\$0.68	\$0.72	\$0.77	\$0.81
DIG Cogen Merchant Unit	\$0.02	\$0.04	\$0.06	\$0.05	\$0.03	\$0.02
EnerBank	\$0.07	\$0.07	\$0.08	\$0.09	\$0.09	\$0.10
Parent Drag and Other	(\$0.37)	(\$0.33)	(\$0.22)	(\$0.20)	(\$0.17)	(\$0.14)
Total CMS EPS UBSe	\$1.77	\$1.89	\$2.02	\$2.16	\$2.31	\$2.46
UBSe Prior			\$2.02	\$2.16	\$2.31	\$2.46
UBSe EPS CAGR 2016-2019						7.1%
Management Guidance - EPS Growth 2017+ (%)			\$1.99-\$2.02			6%-8%
Street Consensus EPS			\$2.02	\$2.18	\$2.33	\$2.49

Source: Company filings, FactSet, UBS estimates

Valuation: Increase PT from \$41 to \$45

Approximately \$2/sh (probability-weighted) of our valuation is linked to energy legislation in Michigan; we have reduced the probability to 50% from 75% previously due to the failure of the legislative session to act in 1H16. We still believe that there could be a material probability that beneficial energy policy will be adopted eventually given the aging coal infrastructure and growing support for renewables.

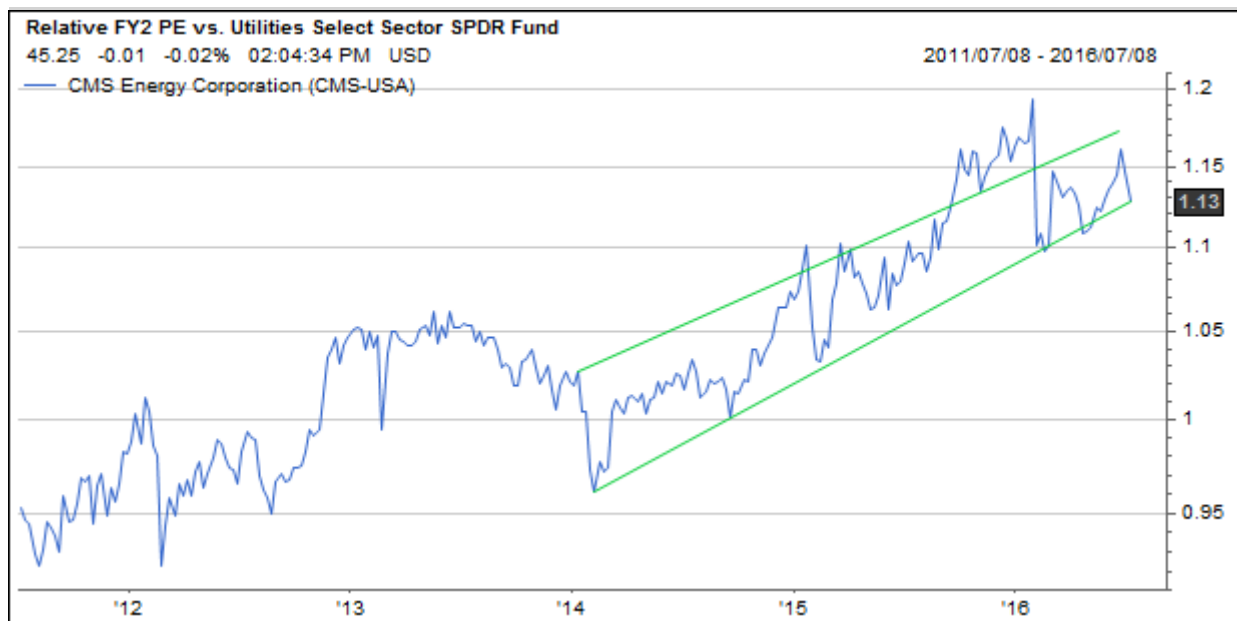
Figure 98: Updated CMS Energy Sum-of-the-Parts Valuation

			Low Case			Base Case			High Case		
Business Segment	Valuation Metric	2018	Valuation Multiple		(\$ MM) Value	Valuation Multiple		(\$ MM) Value	Valuation Multiple	(\$ MM) Value	
Regulated Entities											
						Peer Multiple	Prem/(Disc) to Peer	Base Multiple			
Consumers Electric - Base Capex	P/E	\$1.51	17.0x		\$7,121	18.0x	0.5x	18.5x		\$7,750	\$8,169
Consumers Gas	P/E	\$0.77	17.0x		\$3,621	19.0x	0.0x	19.0x		\$4,047	\$4,260
Incremental Opportunities	P/E			Probability					Probability		Probability
Elimination of ROA		\$0.11	17.0x	0%	\$0		0.0x	18.0x	50%	\$271	19.0x 100%
Renewables - Wind		\$0.07	17.0x	0%	\$0			18.0x	50%	\$183	19.0x 100%
Palisades PPA Expiration		\$0.09	17.0x	0%	\$0			18.0x	50%	\$222	19.0x 100%
MCV PPA Expiration		\$0.11	17.0x	0%	\$0			18.0x	50%	\$265	19.0x 100%
Regulated, Equity Value (\$Mn)					\$10,742				\$12,737	\$14,415	
Regulated, Equity Value (\$/sh)					\$38.60				\$45.77	\$51.79	
Unregulated and Parent Businesses											
EnerBank	P/E	\$0.09	11.0x		\$278		12.0x		\$304	13.0x	\$329
Dearborn Industrial Generation (DIG)	\$kW	770	278		\$214		328		\$252	378	\$291
Parent & Other	P/E	(\$0.17)	19.5x		(\$921)		18.5x		(\$874)	17.5x	(\$826)
Unregulated, Equity Drag (\$Mn)					(\$428)				(\$317)	(\$206)	
Unregulated, Equity Drag (\$/Sh)					(\$1.54)				(\$1.14)	(\$0.74)	
CMS Equity Value					\$10,314				\$12,420	\$14,209	
Fully Diluted Outstanding Shares (2017E)					278				278	278	
CMS Equity Value per Share					\$37.00				\$45.00	\$51.00	

Source: Company filings, FactSet, UBS estimates

CMS' premium relative to the group has continued to expand and is now ~15%.

Figure 99: CMS Relative FY2 PE Multiple



Source: FactSet

Consolidated Edison

We expect a modest miss in the quarter as a number of positive impacts roll off versus last year, such as a 5 cent reserve release (storm costs and 18A assessment), a one cent tax break and a 2 cent amortization benefit. The rate case remains in focus and recent pushback of the hearing timeline suggests settlement talks are progressing as ED has historically done. We also look to the recently released REV track 2 document for indications of future rate structure, which includes both positive incentives and a mandated 10 year depreciation schedule for assets.

Key Drivers: Higher O&M, D&A, and net interest expense more than offset the YoY changes to rate plans. More generally 2015 was a difficult comp year and positive contributions from ConEd Solutions are not likely to continue. Overall we see a ~10 cent miss this quarter as 2016 proves more challenging overall.

Wildcard Factors: Primary unknowns revolve around competitive energy business and to what extent last year's tough comp is offset by any other unknowns. Our ~8 cents of adjustments to CECONY are a substantial contributor to the miss in the quarter but are largely attributable to known positives from 2015.

Figure 100: ED 2Q16E Earnings Walk

ConEd 2Q16 Earnings Walk	EPS
2Q15A Adjusted EPS	\$0.75
Con Edison of New York (CECoNY)	
Changes in Rate Plans	0.07
Impact of Steam in 2Q15	0.00
Impact of Steam in 2Q16	0.00
O&M Inflation and Normalization	(0.03)
D&A and Property Taxes	(0.04)
Net Interest Expense	(0.02)
Oil-to-Gas Conversion	0.01
Other	(0.08)
Orange & Rockland Electric and Gas (O&R)	
Changes in Rate Plans	0.02
O&M	(0.01)
Other	(0.00)
Competitive Energy Businesses	
ConEd Solutions (CES) Ex-MtM	(0.03)
ConEd Development (CED) Ex-LILO	0.01
ConEd Transmission (CET):	0.00
ConEd Energy (CEE)	0.00
Parent & Other (Dilution, Taxes, etc.)	(0.03)
2Q16E Adjusted EPS	\$0.62
2Q16 Consensus	\$0.72
2016 UBSe EPS	\$3.98
2016 Consensus	\$4.00
2016 Guidance	\$3.85-\$4.05

Source: Company filings, FactSet, UBS estimates

Rate Case Update: Settlement Likely Again

Current staff recommendation for CECONY \$45M (1%) rate increase with 8.6% ROE compares to ED request for ~\$480M increase and 9.6% ROE, although about half of the difference in rate base increase is due to lower recommended ROE. The other half is due to staff's NOI adjustments (test period electricity, O&M, depreciation, etc). As for the gas utility, staff recommendation argues for -\$25M

We continue to see shares as pricey, with much of the bid attributable to a 'Yield trade'.

Our concerns remain tied to the risks in midstream execution and ROE downside out of the case...

Potential for a rate case settlement bodes well in the near term

Uncertain factors:

1. Retail sale, finally?
2. REV Proceedings = More or Less capex?

rate reduction (8.6% ROE) compares to ConEd request for \$159M increase on 9.75% ROE. Rockland Electric rate case filed May 13 is seeking 10.2% ROE and \$9.6M rate increase. We had previously calculated likely staff recommendation of 8.34% as shown below:

Figure 101: Our Previous Est for Staff ROE

Required Equity Return	
Constant Growth DCF Methodology	8.95
Three-Step DCF Methodology	8.58
Discounted Cash Flow Methodology (2/3rd Weight)	8.77
CAPM Methodology (1/3rd Weight)	7.49
Required Equity Return	8.34

Source: Company Filings, FactSet, Bloomberg, Yahoo Finance!, and UBS Estimates

Recently it appears that the PSC Staff has been somewhat hesitant to support multi-year deals given the evolving push to reform the regulatory paradigm in the state. All four rate case decisions in 2015 had 9% ROEs (Central Hudson Gas & Electric, CECONY Electric, O&R Gas, and O&R Electric), down from 9.1-9.3% in 2014. Although we expect a relatively flat ROE importantly ED will be able to recover for higher gas inspection related expenses that have significantly impacted the earned ROE at that subsidiary (7.3% actual TTM 9/30/15 vs 9.3% allowed).

Key Date to Watch:

8.17.16 (previously 7.20): hearings begin in rate case. We note hearings postponement likely implies settlement talks are ongoing.

Hearings were postponed as settlement talks progress

Previous timeline

7.20.16: hearings begin

8.29.16 – initial briefs due

9.19.16 – reply briefs due

ED/CEQP: What's going on with Stagecoach?

Our [MLP colleagues](#) recently spoke with Crestwood Equity Partners (CEQP) management to get an update on the new Stagecoach Consolidated Edison (ED) joint venture opportunities. CEQP has discussed the MARC II pipeline in the past and a decision is expected in the near-term. The 700MMcf/day potential project would help connect MARC I with the PennEast Pipeline and cost \$225-\$250Mn, implying \$30-\$35Mn of adjusted EBITDA assuming a 7x EV / EBITDA. When we met with ED recently they said the return targets for Stagecoach were dependent on finding growth/expansion opportunities but few concrete details were available at the time. We look for tangible updates like MARC II to help solidify the growth plan. We believe that in order for the joint venture to be accretive for ED it needs to have further growth materialize beyond just MARC II with management emphasizing double-digit growth in gas demand from Northeast gas utilities (rather than producer-push projects).

When ConEd makes non-utility investments its goal is to earn ROEs at-least equal to the utility (8-9%) – we think this is an easier task for pipeline investments than renewables given the different economic models.

Further information on ConEd and Stagecoach is available below:

[5/16/16 Anticipating Northeast Gas Demand](#)

[4/21/16 Another Utility Branching Out Further into Gas](#)

Hitting a snare on the sell-down of the retail biz?: Based upon our recent conversations with management the company remains committed to the sale of this business – despite some apparent issues in executing. We note interest in retail continues to grow, suggesting some modestly improved prospects. We note the outsized EPS in 2015 could help boost a sale price. We note recent transactions remains in the ~5x EBITDA range, dilutive to ED assuming continued positive EPS; that said, the limited contribution and volatility introduced into its earnings profile does not fit with the contracted and consistent EPS desired by ConEd investors.

A number of competitive generators have discussed a desire to increase their retail presence to better hedge their volume following reduced liquidity in the commodity markets

Renewables in New York?

We await details later this month on the NY PSC's parallel efforts to update the RPS in the state. We note an ongoing debate in the REV proceeding has been to what extent Con Ed in particular can be invested directly in these generation assets (either via utility ownership or third party affiliated). While we're biased to believe they will be largely prohibited, this could provide a further angle of investment if successful. In contrast, we see developments in New York as meriting greater attention for the renewable community.

What Else are We Looking for in the 10-Q?

- Any updates on NY TransCo process
- PSC review of the harlem explosion
- ConEd solutions sales process

Digging into the REV:

Earnings Adjustment Mechanism in REV has multiple angles

Among the most intriguing aspects of the latest Track out of the REV process is the possibility for the NY PSC to award a so-called 'Earnings Adjustment Mechanism' (EAM) to ConEd. This would authorize upwards of 100bp of ROE only to qualifying assets meeting certain criteria. On these projects, largely focused on distributed resources and more novel approaches to solving grid congestion, the project life amortization would be just 10-years rather than conventional utility assets at 20-40+ years. While initially it would appear a novel idea, we caution the short-life of these assets substantially limits their attractiveness.

REV earnings adjustment mechanism could award 100bps incentives, but mandates a 10 year depreciation period

Multiple Other Options Under Rev

On May 19, the NY Public Utility Commission approved Track 2, which is focused on a rate structure to align more closely with REV program goals. Implementation of market-based approaches and proper incentives are key debates as this is rolled out. The plan implements four possible methods for utilities to achieve earnings.

- Traditional Cost-of-Service
- Earnings Tied to achievement of alternatives to reduce capex and benefit consumers
- **Earnings from market-facing platform activities:** This seems to be a particular contentious aspect of the plan since in most cases utilities will be unable to control the outcome directly. The order specifically states that outcome based goals (including mechanisms the utilities do not control) are the most effective methods.

- Transitional Earnings Adjustment Mechanisms: **This is what matters in the near term**, with some rollouts already started at ED.

As part of the REV, ED is already rolling out portions of the program – most notably in the Brooklyn-Queens Demand Management Program (BQDM), which is billed as the rationale behind deferral of construction for \$1B electrical substation in favour of solar, batteries, and energy efficiency. Staff has cautioned that this is focused on a *single project*, whereas the program generally is focused on developer markets. Actual BQDM program goals as laid out include ~41MW of customer sited resources:

Figure 102: BQDM Goals

	2016	2017	2018	Total
Customer Side Solutions	9	23	9	41
Utility Side Solutions	3	8	0	11
Total	12	31	9	52

Source: Company Filings, UBSe

Fleshing out the EAM's

EAM's will be implemented primarily as a transition mechanism towards more mature markets without this level of incentives, and the plan is to implement at the utility either in the next rate filing or as provided in an existing multi year plan. System efficiency, energy efficiency, interconnection (for solar), and customer engagement are key tenants of the EAMs. Additionally, initial bounds on the first round of EAM's specifies a ~100bp max earnings bucket, though this could change over time.

Key Dates to watch:

July 29: ED-specific deadline to file proposal for advanced metering infrastructure and specifically data related to it.

July 31: For ConEdison specifically, the company must add offset tariff and reliability provisions to current rate case – to be implemented Jan 1, 2017 in the case of the reliability credit.

August 1, 2016: Interconnection - proposal for survey process and EAM

October 1, 2016: Clean Energy Advisory Council will propose metrics and targets for **energy efficiency**

November 30: supplemental Distributed System Implementation Plan (DSIP) is due

December 1, 2016: All utilities must file an EAM: Deadline to file peak reduction and load factor targets

Ongoing Filings, no specific date:

Customer engagement

Clean Energy Standard: if Commission adopts Clean Energy Standard, Staff must initiate stakeholder process within 90 days.


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

[5/16/16 Anticipating Northeast Gas Demand](#)
[2/25/16 When Cash Flow and Earnings Don't Mix: Solar](#)
[2/19/16 More Equity Please?](#)
[1/26/16: What Lies Behind the Defensive Veneer](#)
[10/9/15 Fitting Renewables Into the Mix](#)
[8/13/15 A Green Lining in the Clouds](#)
[5/05/15 Consolidating Edison](#)
[2/24/15 ROE Risk Remains in Focus](#)

Valuation: Increase price target to \$72 from \$66

Our valuation remains based on 2018 P/E methodology. We continue to apply a 5% discount to shares *given the lack of load growth, below-average earned ROEs, and lingering uncertainty around the March 2012 Harlem blast. The increase in our price target is driven entirely by the 1.5x-turn improvement in the regulated peer multiple.*

Figure 103: Consolidated Edison Valuation

Consolidated Edison Valuation 			
Regulated 2018 P/E Multiple		18.0x	
	Down side	Base Case	Upside
2018 EPS	\$4.10	\$4.20	\$4.30
x P/E Multiple	18.0x	18.0x	18.0x
(Discount)/Premium	-10%	-5%	10%
Valuation	\$66.00	\$72.00	\$85.00
Upside/(Down side)	-17%	-9%	7%
Assumed CECONY ROE	8.7%	8.9%	9.1%

Source: Company filings, FactSet, UBS estimates

Dominion Resources

What about 2Q? Flattish YoY

We include our initial estimate of our 2Q YoY walk for EPS estimates, illustrating largely the substantial impact of the Millstone outage in 2Q16 results. We emphasize the largely inline weather should drive a quiet quarter.

Expect a slightly better than midpoint quarter – but focus is on the 2017 prospect for a flattish outlook

Figure 104: 2Q YoY Walk comparing vs. Guidance

Last year vs Guidance	2Q15 ABS	2Q16 Low	2Q16 High	2Q16 Mid		2Q15A	0.73
VEPCO (w eather normalized)						2Q16 vs normal	0.02
Elec Dist	209	180	205	193		VEPCO (w eather normalized)	
Elec Trans	165	175	185	180		Elec Dist	(0.02)
Utility Gen	402	425	460	443		Elec Trans	0.02
D&A	(231)	(250)	(255)	(253)		Utility Gen	0.05
Regulated Gas (w eather normalized)						D&A	(0.02)
Gas Dist	81	80	90	85		Regulated Gas (w eather normalized)	
Gas Trans	205	235	255	245		Gas Dist	0.00
D&A	(64)	(65)	(65)	(65)		Gas Trans	0.05
Merchant Gen	144	65	85	75		D&A	(0.00)
D&A	(34)	(40)	(40)	(40)		Merchant Gen	
Interest	(221)	(240)	(230)	(235)		D&A	(0.08)
Corp & Other	(26)	(45)	(45)	(45)		Interest	(0.02)
Income Taxes	(201)	(140)	(165)	(153)		Corp & Other	(0.02)
Income Tax Rate	32%	27%	26%	26%		Income tax rate	0.06
Operating Earnings after-tax	429	380	480	430		Dilution	(0.02)
Shares	593	614	612	613		2Q16E	0.73
EPS	0.72	0.62	0.78	0.70		Consensus	
EPS Guidance Range				0.90-1.05		2Q16 Guidance	0.65-0.75
						2016 Guidance	3.60-4.00

Source: Company reports (left table) and UBS estimates

What matters for this quarter?

- **2017 EPS positioning – and hedge position for Millstone.** We look for mgmt to provide an update on their hedge progress at the nuclear plant, as well as energy prospects amidst the nascent recovery in gas.
- **Solar ITCs: Just how much are there in guidance & more?** We look to understand just how much in ITC recognition the company will have in their 2016-2018 results from both their regulated and utility operations following continued success with C&I customers in VEPCO.

Awaking the Midstream Mogul (From our July 6th Note)

2017 is still the focal point in discussions as commodities point to flat EPS

We hosted our latest NDR with Dominion Resources where questions remains focused on 2017E EPS, which appears to be largely flat YoY despite the wider 6-7% EPS growth ambition through 2020. While our estimates already reflect this expectation, we see some risk for further moderation. Despite this risk of further EPS estimate easing, we note investors appear to be focusing back on the story amidst an effort to find value.

2018 estimates are where investors should be focused; can it get back on track?

While investors remain focused on 2017E, we see the real debate as 2018E (and what the precise level of YoY improvement will be based on improving trends for the Cove Point due to seemingly improved financing terms, likely ahead of the \$0.40 EPS initially targeted with ~\$600-800 Mn in EBITDA the formal goal). Further solar in 2018 (and ensuing 1x EPS benefits from ITCs) remains a real possibility to ensure 7-9% EPS

growth through the 2020 period seemingly off low 2017 base. Roll forward of investor expectations in 2H towards 2019 will highlight the step-up from Atlantic Coast Pipeline (~\$0.20) alongside other investments, driving the ~7% growth targeted. While our '18E is now below Street, we see offsetting factors to stabilize EPS at current levels including STR accretion and potential upside on Cove Point (we assume ~\$650Mn.)

Dividend growth could see further acceleration? Yes, as CFPS exceeds EPS

DPS growth is core to recognizing the uptick, exceeding EPS growth in 2018+ once DM achieves greater than the 50% GP splits, perhaps exceeding the 8% guidance off 2014, albeit funded by a further step-up in payout ratio. The further corresponding question is how meaningful will corporate deleveraging be once the Cove Point asset reaches in-service in 2018? We note the more leveraged 14% FFO/Debt leaves D in a distinctly different position than infrastructure peers SRE and NEE.

But what do we think about shares?

We continue to believe that shares deserve a premium valuation versus peers given the 6-7% overall EPS growth, or more importantly, accelerated near-year EPS growth of 7-9% off 2017. The challenge is that shares might not represent an attractive risk/reward through the estimate revision cycle, hence our neutral viewpoint. While perhaps the lower EPS estimates of late could be reflecting the lows in the Millstone commodity cycle, the wider backdrop remains moderation of EPS expectations and in turn how management will handle any repositioning of its outlook. Specifically we look at both EPS and DPS prospects as well where an acceleration of the dividend per share could offset earnings per share concerns.

Millstone commodity volatility clouds the EPS outlook relative to the more visible infrastructure projects later in the decade.

Top Emerging Debates

- **How much will Cove Point contribute?** Management has continually referred to Cove Point in terms of a potential EBITDA uplift and we see upside to earnings per share based on evolving financing assumptions. Dominion has typically discussed an approximately equal amount of debt and equity financing here but we believe this could shift.
- **Solar: will the tax breaks continue into 2018?** While we had initially expected the solar ITCs to largely prove a transition element, we look for ITCs to continue to benefit 2018 at least modestly, largely with the ~400 MWs of regulated solar contemplated in addition to a handful of other ~quasi regulated C&I contracts under evaluation in VA. Net-net, we think this could mean the EPS fall-off YoY is unlikely to be the full ~\$0.15/sh (mgmt does caution this is not a scenario in which all 400 MWs are pursued in '18 alone). Further ITC benefits in 2018 would be driven by non-regulated investments, to which management expects few of late but this could well change. Should ITCs continue into 2018, we believe investors would raise questions around solar contributions and the overall EPS quality in a more meaningful manner.
- **Where else is the growth in midstream?** With natural gas pricing under-pressure, we do not have a high degree of confidence on incremental midstream growth projects outside of those currently underway. Approximately ten smaller projects remain underway and should each contribute discretely a limited uplift in 2017+. Management appears focused on incremental PJM and Southeast generation hook-ups into its new pipe system to prove the bulk of incremental Dominion Energy segment uplift beyond the two core projects. We think the EPS benefits here appear modest, but still an incremental growth opportunity.

Investors continue to debate earnings quality given the reliance on tax credits today.

Growth at Blue Racer given its Gathering and Processing (G&P) exposure remains less certain.

Other Key Issues

LNG: Investors concerns over the LNG theme

Investors continue to question the risk to earnings at Cove Point but management has emphasized that there is no reopener risk to Dominion on its LNG export offtake arrangements. We remain relatively surprised by the extent of investor concerns around this point; we see this as an opportunity as this risk declines through time. The sole emerging-market counterparty is Gail (listed on the National Stock Exchange of India [NSE]) which is majority-owned by the Indian government. Rather the focus remains getting Cove Point to an in-service by mid-2017 for testing and startup; full year operations are expected in 2018.

New Generator Interconnects: Southeast and Mid-Atlantic

Mgmt emphasized opportunities for its Dominion Energy to contract with new electric generation stations as part of its growth capital. While this angle remains clear with respect to its greenfield pipelines (Atlantic Coast and Cove Point), a further angle remains whether further PJM gas plants will interconnect into the Dominion system, likely at modest incremental cost to D itself.

Revenue from new interconnections could be a positive but more modest.

More Pipelines: Focus will be on extending pipe network too

We look for management to continue to focus on expanding its infrastructure across the core Southeast, albeit maintaining a ~50% stake in all projects in which it is the operator. We understand there is interest from Southern Company to own interstate pipelines (following a recent Bloomberg interview) and see prospects to partner. We look for developments on any such future projects in the medium term as further growth projects which could feed into 2019 & 2020 growth (not yet reflected in our Dom Energy segment).

The GP math drives the story into 2018 and beyond

We remain confident further pipeline project potential exists into 2019 to drive continued YoY growth; the opportunity here remains largely tied to impacts of the first (few) drops at full GP 50% splits on incremental cash flows. Overall management frames the GP driven EPS-growth back at D as contributing at least ~2% from the core 5-6% of the core businesses up to the 7-9% contemplated at the consolidated level.

DM: Solving for the Drop Down Pipeline

Dominion downplayed further interest in M&A following its latest (and still pending) deal for Questar. We emphasize the deal was principally based on providing a further set of drop-down assets for DM as its Blue Racer subsidiary has failed to scale to the extent initially contemplated. With the Questar deal, the company appears to have locked in transient 2017 drops (beyond the assets acquired from SCG in SC), providing a runway to the Cove Point assets in 2018. Given the meaningful size of Cove Point itself, we think the \$600-800 Mn of EBITDA would appear likely to be dropped in approximately three segments.

Financing the Acquisition, Still

We note our estimates continue to exclude the acquisition of STR from our financials, which is estimated to contribute ~\$0.08-0.10 under our current financing assumptions. We note a remaining ~\$2.4 Bn of equity has yet to be funded, which could be funded with a combination of Mandatory Converts, Issuances from DM to fund immediate drops, and/or acceptance of DM units back

at the parent (creating further mandatory funding need). We also could see a mismatch in timing between when a drop is pursued and total financing with the bridge loan offered with the deal enabling one-year of latitude. See our original thoughts on the deal [here](#).

Closing the Questar Deal; No Further M&A Plans

Mgmt remains confident on its ability to close the pending STR deal later this year. Moreover, management was relatively quick to step back from anything further amidst this pending transaction. A focus on de-leveraging the balance sheet appears to be in place for 2018+.

The VEPCO Outlook: Overcoming the Odds

The outlook for the core regulated utility in Virginia appears largely intact given the existing arrangement to freeze base rates, with the first opportunity to adjust these following recent legislation pushed out to Jan 1, 2023 (following an outcome in which the Va SCC determined the company had indeed modestly over-earned in the last review period for 2013-14). Other datapoints have remained mixed. We also note several of the recent rider projects with separately dictated ROEs have been established at 9.6% ROE base (current trailing national average for authorized) albeit at a +100bp positive spread, implying an effective authorized ROE of 10.6%. More importantly, regulators acknowledged the benefits of lower capacity expense due to replacement of capacity provided from Non-Utility Generation (NUG) contracts with rider-based generation, in this case the Greenville plant (albeit ultimately did not adjust rates to offset this benefit). Bottom line, while datapoints on the regulatory front would appear to be less constructive on the margin, we believe the core utilities remain largely insulated from any meaningful shifts. Given these developments, we see a longer-term risk emerging around ROE normalization of its above-average earned ROEs in Virginia.

How to think about the eventual VEPCO risks and valuation? The wider question emerging remains how to think through putting a premium multiple on the VEPCO regulated utility given its risk of an eventual ROE cut back towards more 'normal'. Our continued willingness to ascribe a premium to the utility is tied to the near-term sustainability of this ROE along with its above-average growth prospects (~8% given continued push to make Virginia self-sufficient, rather than a net importer from adjacent states. Overall, we perceive more limited upside arising from this segment in our Sum of the Parts.

Updates this Fall? Not much on the capex front

We don't perceive any meaningful updates this Fall with its usual Capex update cycle post Labor Day. This could mark the first year in recent memory at which time the company did not provide a meaningful update on its prospects mid-year.

EPS Estimates

We include below our latest estimates. While our '18 EPS estimate could yet see further degradation at Millstone and elsewhere, we reflect a more conservative \$650 Mn in EBITDA for Cove Point in '18 (vs. the total \$600-800 Mn guided by management including the ~\$80 Mn remaining from legacy import contracts continuing until 2023). We think Street estimates on '18 could yet moderate modestly as well as expectations on commodities are fully reflected (we note our estimates reflect the latest recovery in New England power price expectations for Millstone as well). We further caution that our estimates do not yet reflect the

~\$0.08-0.10 of EPS accretion resulting from the STR acquisition (which would put our '17 estimate roughly near the midpoint of '16 EPS guidance). This remains the primary positive variance in Street revisions on shares.

Figure 105: Dominion EPS estimates

Dominion EPS by Segment	2014A	2015A	2016E	2017E	2018E	2019E
Dominion Virginia Power	0.86	0.83	0.91	1.10	1.24	1.36
Dominion Energy	1.29	1.12	1.18	1.10	1.54	1.74
Dominion Generation	1.88	1.89	1.71	1.69	1.76	1.69
Corporate and Other	(0.60)	(0.39)	(0.01)	(0.12)	(0.31)	(0.28)
Total UBS EPS Estimate	3.43	3.44	3.79	3.77	4.23	4.50
UBSe (Prior)	3.43	3.44	3.79	3.76	4.35	4.36
Guidance			3.70-4.05			

Source: Company reports, FactSet, and UBS estimates

Millstone gave D the Guidance issues of late– can it help get it out?

We emphasize management is holding off on hedging its Millstone nuclear plant in CT (largely open into 2017 and 2018) in an effort to 'wait' for the commodity environment to improve in 2H. We don't look for formal 2017 EPS guidance until the usual reporting framework with 4Q16 results, in contrast to earlier contemplations to release this in an expedited manner to firm up Street concerns on just how low this year could land. We note this makes D *more* subject to shifting (more constructive) commodity attitudes in 2H; in particular the recent delay in the Constitution pipeline has helped firm up New England gas prices once more on the Algonquin basis.

We continue to forecast positive FCF through the period

We see potential for 2H improvement in New England gas prospects

We emphasize the shifts in capacity prices through 2016-2018 is offsetting in part the loss of energy margins. We also flag our estimates continue to show the plant generating positive cash flow even after the hedges rolloff.

Figure 106: Estimated Millstone Plant Economics Summary

Millstone Nuclear Plant	2015A	2016E	2017E	2018E	2019E	2020E
Capacity	2,016	2,016	2,016	2,016	2,016	2,016
Capacity factor	90%	95%	90%	90%	95%	90%
Output (TWh)	16	17	16	16	17	16
% Hedged	100%	93%	8%	0%	0%	0%
Market price (\$/MWh), Mass Hub ATC	53.13	41.90	40.38	40.45	40.76	41.26
Hedge Price (\$/MWh)	56.98	51.50	42.14	-	-	-
Weighted Avg. Price (\$/MWh)	56.98	50.68	38.67	38.43	38.72	39.19
Nuclear Fuel Costs (\$/MWh)	7.5	7.5	7.9	8.5	8.5	8.5
Energy Margin (\$/MWh)	49	43	31	30	30	31
Energy Margin (\$ Mn)	788	723	490	476	506	488
O&M (\$/kW-Yr)	230	230	230	230	230	230
O&M (\$ Mn)	464	464	464	464	464	464
Capacity Revenues (\$ Mn)	74	72	128	206	195	170
EBITDA (\$ Mn)	398	332	154	218	237	195
YoY Shift in EBITDA		(66)	(177)	64	19	(43)
YoY Shift in EPS @ 35% Tax rate		(0.07)	(0.19)	0.07	0.02	(0.04)
Maintenance Capex	(101)	(101)	(101)	(101)	(101)	(101)
FCF Estimate	297	231	54	117	137	94

Source: Company reports and UBS estimates

Valuation: Maintaining PT of \$77

We are maintaining our Price Target to \$77 which remains based on a sum-of-the-parts methodology: a combination of peer utility 2018E P/E, EV/EBITDA for the gas business, and DCF for its holdings of Dominion Midstream (DM) MLP LP and GP units. We continue to view D as fairly valued as there is increased uncertainty over midstream growth prospects in the Marcellus and Utica shales (limiting focus for further expansion on the Access projects and larger greenfield pipeline efforts).

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

[5/24/16 Feasting on ITCs from the Millstone](#)

[5/3/16 Giving New Life to Nuclear In New England](#)

[3/30/16 Dousing the New England Grid](#)

[2/12/16 Read All About It: Why The New England Print Matters](#)

[2/11/16 Pouring Cold Water on New England Power](#)

[2/2/16 D: Going West for the Quest](#)

[2/1/16 DM: Solid Quarter, Drop Pipeline Enhanced](#)

(report from Shneur Gershuni)

[2/1/16 STR: Combining with Dominion Resources](#)

(report from Shneur Gershuni)

[1/29/16 A Plainer Domain \(Downgrade to Neutral\)](#)

Figure 107: Dominion Resources Sum of the Parts Valuation on 2018E

Dominion (D) Sum of the Parts Analysis - UBSe							
	2018E Adj. EBITDA		EV/EBITDA			Enterprise Value	
		Downside	Base	Upside	Downside	Base	Upside
Dominion Merchant Generation	440	6.0x	7.0x	8.0x	2,642	3,083	3,523
Hedge Value	-	6.0x	7.0x	8.0x	-	-	-
Normalize to 2019 capacity price	(12)	6.0x	7.0x	8.0x	(74)	(86)	(98)
Dominion Energy (DTI & Iroquois)	1,138	10.0x	11.0x	12.0x	11,383	12,522	13,660
Dominion Midstream Partners Minority Interest	(94)	10.0x	11.0x	12.0x	(940)	(1,034)	(1,128)
Dominion Retail	61	4.0x	5.0x	6.0x	245	306	367
Total / Implied	1,534	8.6x	9.6x	10.6x	\$ 13,257	\$ 14,791	\$ 16,324
Value per Share					\$ 21.52	\$ 24.01	\$ 26.50
Phase 1 MLP through 2020							
Discount rate applied to LP and GP distributions					10.0%	8.5%	8.5%
Terminal growth rate applied to LP and GP distributions					0.0%	2.0%	4.0%
LP Distribution Equity Value NPV					1,377	2,061	2,946
GP Distribution Equity Value NPV					1,151	1,821	2,811
PV of Compensation for Dropdowns from DM					3,283	3,314	3,452
add: NPV of 2016 and 2017 cash flows from Cove Pt Import					347	251	347
Total Equity Value of MLP Phase 1					\$ 6,158	\$ 7,448	\$ 9,556
Value per Share					\$ 10.00	\$ 12.09	\$ 15.51
Phase 2 2018+							
LP Distribution Equity Value NPV					1,780	2,714	3,804
GP Distribution Equity Value NPV					2,226	3,519	5,269
PV of Compensation for Dropdowns from DM					5,422	5,766	5,936
Minus DTI, LDCs, & Iroquois Equity Value (before MLP dropdown)					(11,663)	(12,110)	(11,663)
Total Potential MLP Phase 2 Incremental Uplift to SOP					\$ (2,235)	\$ (110)	\$ 3,347
Probability					80%	80%	80%
MLP Phase 2 Incremental Uplift to SOP					\$ (1,788)	\$ (88)	\$ 2,677
Value per Share					\$ (2.90)	\$ (0.14)	\$ 4.35
Net Implied GP Value per Share					\$ 4.76	\$ 7.53	\$ 11.41
less Total Dominion net debt						(28,344)	
netting VEPCO-associated debt						11,023	
netting VEPCO debt allocated to HoldCo (assuming lever up to 60% debt/cap)						1,895	
netting Gas LDC-associated debt						1,265	
netting MLP Phase 1 debt allocated to HoldCo (at 3.5x EBITDA)						3,063	
add: NPV of Merchant Generation Hedges						146	
Net Energy/Generation Debt					\$ (10,951)		
Value per Share					\$ (17.78)		
Dominion Energy, MLP, Merchant Generation, and Retail					\$ 6,675	\$ 11,199	\$ 17,606
Current Number of Shares outstanding					616	616	616
Dominion Energy, MLP, Merchant Generation, and Retail per Share					\$ 10.84	\$ 18.18	\$ 28.58
Peer P/E Multiple 17.8x Premium 1.0x							
Dominion Delivery							
	2018 Net IncoR/E Multiple						
Electric	407.96	17.8x	18.8x	19.8x	7,262	7,670	8,078
Transmission	353	17.8x	18.8x	19.8x	6,285	6,638	6,991
Dominion Generation-Utility	981	17.8x	18.8x	19.8x	17,463	18,444	19,425
Total VEPCO Net Income	1,742	17.8x	18.8x	19.8x	31,009	32,751	34,493
Value per Share					\$ 50.34	\$ 53.16	\$ 55.99
Gas Distribution LDCs							
East Ohio	185	17.8x	18.8x	19.8x	3,300	3,486	3,671
Hope Gas	10	17.8x	18.8x	19.8x	185	195	206
Total Gas Distribution Net Income	196	17.8x	18.8x	19.8x	3,486	3,681	3,877
Value per Share					\$ 5.66	\$ 5.98	\$ 6.29
Current Number of Shares outstanding					616	616	616
Dominion Regulated Utilities SOP Value (\$/sh)					\$ 55.99	\$ 59.14	\$ 62.29
Total Equity Value per Share					\$ 67.00	\$ 77.00	\$ 91.00

Source: UBS Estimates, Company Filings, FactSet

DTE Energy Co.

Shares have been steadily outperforming since the March lows as confidence on the unregulated business outlook has grown, despite the failure of Michigan energy legislation to be approved. We continue to see DTE as attractively positioned.

We forecast 2Q16 adjusted EPS of **\$0.85** vs \$0.76 in 2Q15 and \$0.88 Consensus.

- **Key Drivers:** The revenue decoupler amortization is the most significant headwind, similar to 1Q16, but the electric rate implementation should more than compensate for the unfavorable comparison. Continued growth at the unregulated business should also contribute to YoY improvement.
- **Wildcard Factors:** (1) Magnitude of O&M saving efforts to offset the mild winter weather. The decision to implement the 'lean' vs 'reinvestment' plan typically occurs later in the year but the 1Q16 weather headwind was particularly large; (2) performance of the volatile trading business which was +\$3Mn in 2Q15; (3) timing of any tax items

CMS discussed levers it can pull to offset the challenging 1Q16 weather, above the typical rate reduction efforts the company strives to achieve.

Figure 108: DTE 2Q16E Earnings Walk

DTE Energy 2Q16 Earnings Walk	EPS
2Q15A Adjusted EPS	\$0.76
Regulated Utilities	\$0.08
Weather vs Normal in 2Q15 -\$4Mn Electric & Gas	\$0.02
Weather vs Normal in 2Q16	\$0.02
2015 DTE Electric Case: +\$243Mn in Dec. 2015	\$0.18
2016 DTE Electric Case: +245Mn in Aug. 2016	\$0.00
2016 DTE Gas Case: +103Mn in Nov. 2016	\$0.00
Revenue Decoupler Amortization	(\$0.11)
Electric Sales Growth: 0.0%-0.5%	\$0.00
Gas Sales Growth	\$0.00
O&M: Reinvestment vs. Lean Initiatives	\$0.00
Property Taxes, Depreciation, & Other	(\$0.03)
Unregulated Businesses	\$0.01
P&I: Volume at REF sites; weighted in 2H	\$0.01
Midstream: Continued investment in gathering system	\$0.01
Trading: +\$3Mn in 2Q15; assume is flat	(\$0.02)
Corporate & Other	(\$0.00)
Taxes: Timing	\$0.00
Dilution	(\$0.00)
2Q16E Adjusted EPS	\$0.85
2Q16 Consensus	\$0.88
2016 UBSe EPS	\$4.93
2016 Consensus	\$4.95
2016 Guidance	\$4.80-\$5.05

Source: Company Filings, FactSet, and UBS Estimates

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

[4/27/16 A Confident Stride](#)

[2/12/16 Running Leaner on Less Equity](#)

[10/26/15 Tooling Up for More in 2016 after Strong 3Q](#)

[9/30/15 Upbeat Analyst Day Saves More for Next Year \(2016\)](#)

[7/27/15 Votes of Confidence](#)

What are the key updates for DTE?

- **Resetting expectations for MI legislation:** The Michigan state legislature entered their summer recess in early June without holding a vote on the energy legislation. When the bill was up for debate media reports indicated that there were multiple aspects of the potential legislation being debated such as the ultimate terms for consumer choice/'switching' and renewables mandate/goal. Importantly, Senate Energy and Technology Committee Chair Senator Mike Nofs (R) will remain in the legislation and continue to advocate for legislation. The challenge for next year will be that there is expected to be an education period for any new Representatives which could make the process more challenging.
- **Staff positions in electric and gas come in:** DTE's electric and gas rate cases continue to progress with the PSC Staff having made recommendations recently. In the electric case the PSC Staff recommended a +\$189Mn rate increase (10% ROE) versus DTE's request of +\$344Mn (10.5% ROE). In the previous rate case the PSC Staff and ALJ also recommended a 10% ROE and the final authorized ROE was 10.3%. The electric rate case has had a higher profile than typical rate cases due to the MI Attorney General Bill Schuette's intervenor filing regarding bill inflation. In the gas case the PSC Staff recommended a +\$123Mn (10% ROE) revenue increase compared with +\$182Mn (10.75% ROE). Management has filed to implement a +\$144Mn increase which is +\$103Mn net of the Infrastructure Recovery Mechanism.

ALJ Proposed Decisions are expected in October (Gas) and November (Electric) with self-implementation in November (Gas) and August (Electric).
Docket C-U-18014 (Electric) and Gas (C-U-17999)

- **New Independent added to the PSC:** On July 6th Michigan Governor Rick Snyder appointed Rachael Eubanks (I) to the Michigan Public Service Commission to serve the remainder of John Quackenbush's term through July 2017. The appointment is still subject to Senate confirmation.
- **NEXUS takes another step forward with draft EIS; overcoming the doubts:** On July 8th the FERC staff released the draft Environmental Impact Statement (EIS) for the DTE's jointly-owned NEXUS pipeline which concludes that if mitigation measures are implanted there would not be significant permanent environmental impacts. This important milestone is key for the 1.5BCf/day project to achieve its 4Q17 in-service date. Although investors will not have true visibility into the 1.75BCF/day of incremental interconnection agreements, management has confidence enough to order compressors for the additional capacity. As a reminder of the primary 1.5BCF/day capacity, 3/4th is contracted (half shippers/half LDCs).

When we last met with management, DTE stated that it was in the process of 'firming-up' yet another LDC gas deal with an Ohio utility (already short-listed with an MOU), adding to its existing firm offtakes from a range of MI and Ontario based utilities. Further, management emphasized progress is clear on the offtake from the Oregon CCGT, among the largest incremental gas users in the Ohio footprint for the pipe. Lastly, despite seemingly making statements otherwise, DTE emphasized NRG continues to evaluate a gas lateral to reach its Avon Lake coal plant as part of an option to move the plant to partial service. We emphasize the conversion would have limited total usage but was

The question is how much turnover will occur in the House – if there are significantly more new Representatives this lack of continuity could make the process more challenging in 2017.

NEXUS progressing forward with higher volumes

a recent seeming loss when the project appears to have recommitted itself to burning low-sulfur PRB as part of its MATS compliance strategy.

- **Bolt-on acquisitions remain under consideration but no progress yet.** DTE is actively looking at possible acquisitions of existing projects, although no specific projects have yet met management's strict investment criteria yet, despite the distress of many of the midstream companies. We see capital market weakness for MLPs as possibly limiting competition for assets while also possibly removing any remaining incentive for management to consider an MLP structure for itself (or to sell its assets to one).
- **Addressing the expected 2020 falloff in tax credits for P&Is.** Reduced Emission Fuel (REF) business, which is currently operating in nine sites. Additionally, DTE is now operating a third-party REF facility with an operating agreement through 2020. Management continues to "work towards further optimization" of this segment, with the goal of generating significant cash flows to fund other non-utility growth projects. Emphasis for this segment remains on the CHP (Combined Heat and Power) opportunities in a cheap gas price environment, positioned to provide an array of products on a 'behind the meter' basis.

On the 4Q call, guidance for 2019 was reduced \$25M to \$120M (mostly lower Industrial Energy Services income) and the REF business is expected to experience a \$30M (\$0.15/sh) drop in tax credits in 2020 with the remainder rolling-off in 2022.

UBS estimates unchanged

Figure 109: UBS Earnings Estimates, 2014A-2020E

DTE Energy EPS Estimates	2014A	2015A	2016E	2017E	2018E	2019E	2020E
DTE Electric	\$2.99	\$3.12	\$3.26	\$3.52	\$3.67	\$3.81	\$3.93
Incremental Generation Capex Opportunities			\$0.00	\$0.10	\$0.19	\$0.36	\$0.42
DTE Gas	\$0.79	\$0.77	\$0.77	\$0.82	\$0.88	\$0.95	\$0.98
Midstream	\$0.46	\$0.56	\$0.61	\$0.68	\$0.75	\$0.83	\$0.92
Power & Industrial Projects	\$0.51	\$0.56	\$0.53	\$0.59	\$0.65	\$0.71	\$0.56
Trading	\$15.85	\$0.11	\$0.00	\$0.00	\$0.00	(\$0.00)	(\$0.00)
Parent & Other	(\$0.74)	\$0.24	(\$0.24)	(\$0.35)	(\$0.32)	(\$0.28)	(\$0.25)
DTE Energy	\$4.60	\$4.82	\$4.93	\$5.35	\$5.83	\$6.38	\$6.57
Prior UBSe		\$4.82	\$4.93	\$5.35	\$5.83	\$6.38	\$6.57
DTE Energy without incremental opt'y	\$4.60	\$4.82	\$4.93	\$5.25	\$5.63	\$6.02	\$6.15
Street Consensus	\$4.60	\$4.82	\$4.95	\$5.26	\$5.63	\$5.98	\$6.20
Midpoint of mgmt guidance 5%-6% from 2016 \$4.93 to 2020			\$4.93	\$5.20	\$5.48	\$5.78	\$6.10
Management guidance			\$4.80-\$5.05				

Source: Company Filings, FactSet, and UBS Estimates

Valuation: Increase Price Target \$4 to \$108

Our valuation is now based on a utilities 2018E sum-of-the-parts with a half turn premium P/E multiple for the electric utilities and a 1x premium for the gas utility. We assign EV/EBITDA for the unregulated businesses. Similar to CMS, we have lowered the probability of incremental Retail Open Access (ROA) and renewables related capex to 50% from 75%; this change offsets approximately half of the uplift provided by a 1.5x-turn improvement in the regulated utility peer multiple since our last mark-to-market.

What's changed in our PT?

-\$5/sh: Lowered probability of near-term incremental spending
+9/sh: 1.5x-turn increase in regulated utility peer multiple

Figure 110: DTE Sum-of-the-Parts Valuation on 2018E

Business Segment	Prob	Valuation Metric	2018E	Low Case		Base Case		High Case	
				Valuation Multiple	(\$s MM) Value	Valuation Multiple	(\$s MM) Value	Valuation Multiple	(\$s MM) Value
<u>Regulated</u>						Regulated Peer Multiple 18.0x			
DTE Electric		P/E	\$3.66	17.5x	\$11,648	18.5x	\$12,314	19.5x	\$12,979
Incremental ROA, Renew ables Capex	50%	P/E	\$0.19	17.5x	0	18.5x	626	19.5x	1,320
Incremental 2020-2024 New Generation	50%	P/E	\$0.24	17.5x	0	18.5x	399	19.5x	1,680
DTE Gas		P/E	\$0.88	18.0x	2,873	19.0x	3,032	20.0x	3,192
Regulated, Equity Value					\$14,521		\$16,371		\$19,171
<u>Unregulated Business</u>									
Power Projects		EV/EBITDA	\$252	8.0x	\$2,016	10.0x	\$2,520	11.0x	\$2,772
Midstream		EV/EBITDA	\$238	10.0x	2,384	12.0x	2,860	13.0x	3,099
Trading		EV/EBITDA	\$1	3.0x	3	5.0x	5	6.0x	6
Parent & Other Overhead		EV/EBITDA	\$88	8.0x	704	10.0x	880	11.0x	968
Less: Parent Debt, Net (2018E)					(2,967)		(2,967)		(2,967)
Unregulated, Equity Value					\$2,140		\$3,299		\$3,878
DTE Equity Value					\$16,660		\$19,669		\$23,049
Fully Diluted Outstanding Shares (2018E)					182		182		182
DTE Equity Value per Share without incremental opportunities					\$92.00		\$102.36		\$110.50
DTE Equity Value per Share including incremental opportunities at probability					\$92.00		\$108.00		\$127.00

Source: Company Filings, FactSet and UBS Estimates

Duke Energy

Investors continue to debate whether DUK deserves a premium to peers – we continue to believe yes as it moves to a pure-play regulated utility and meets the demand for ‘cheaper’ defensive utility plays. Pricing on the Latin American divestiture is an important datapoint but we perceive the most investor caution around coal ash spending and the subsequent regulatory treatment. We think clarity here could be a significant driver for shares. We believe favorable regulatory treatment for coal ash could push the EPS growth profile towards the higher end of its 4-6% seemingly YoY later in the decade.

We forecast 2Q16 adjusted EPS of **\$1.05** vs \$0.95 in 2Q15 and \$1.00 Consensus.

- **Key Drivers:** 1Q16 O&M was -\$0.05 drag relative to plan due to storm expenses which drove the regulated utilities down -\$0.01 YoY excluding weather. We expect a normalization of O&M and +\$0.07 improvement at the utilities excluding weather, consistent with the original FY16 guidance. The net weather comparison is a headwind but 2Q16 heat could be a partial offset.
- **Wildcard Factors:** (1) [Improvements in the hydrology conditions](#) should more than offset unfavorable F/X and crude comparisons; (2); Timing of taxes at international where management guided to “a modest” reversal of the +\$0.11 recorded in 1Q16 in the balance of 2016E; (3) Better wind production YoY [renewables segment was actually down YoY in 2Q15 despite more capacity].

A ‘normal’ level of O&M at the regulated utility, net improvement in the Brazilian hydro situation, and more renewables with better resources should help deliver +\$0.10 EPS improvement YoY and a solid beat versus Consensus.

Figure 111: DUK 2Q16E Earnings Walk

Duke Energy 2Q16 Earnings Walk	
2Q15A Adjusted EPS	\$0.95
Regulated Utilities	
Weather vs Normal in 2Q15 +\$65Mn Pre-Tax Impact	(\$0.06)
Weather vs Normal in 2Q16	\$0.02
Capital Investments: +\$0.08 riders YoY for FY16	\$0.02
O&M: Commentary to reduce in 2016 vs 2015	\$0.02
Load: Growth (+~0.60bp with 100 bps ≈ \$0.10 EPS FY)	\$0.01
Wholesale Growth: \$0.01-\$0.03 incremental in 2016 vs \$0.10 in 2015	\$0.00
Purchased NCEMPA July 31, 2015 for \$1.25Bn (full quarter YoY)	\$0.03
Accretion from Piedmont Transaction: Expected to close in 4Q16	\$0.00
Depreciation, property taxes, interest, and other	(\$0.02)
Commercial: Renewables & Midwest Generation	
Absence of Midwest Generation: Transaction closed 4/2/15	\$0.00
Reversal of 2Q15 below-average renewable generation	\$0.02
Renewables - expect \$1B-\$2B incremental investment 2015-2017	\$0.02
International and Other	
Brazil: Impact of F/X (~\$0.015 annualized for 10% change)	(\$0.01)
NMC: Impact of Brent Crude (~\$0.015 annualized for \$10/bbl change)	(\$0.00)
Hydro: Improving hydro/reservoir conditions (Long in '16 vs Short '15)	\$0.04
Timing of taxes: Reversal of portion of 1Q16 benefit	(\$0.01)
Impact of Accelerated Stock Repurchase Program	\$0.00
2Q16E Adjusted EPS	\$1.05
2Q16 Consensus	\$1.00
2016 UBSe EPS	\$4.65
2016 Consensus	\$4.59
2016 Guidance	\$4.50-\$4.70

Source: Company Filings, FactSet, and UBS Estimates

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

[5/5/16 In Search of a Latin Suitor](#)

[2/22/16 Holding The Line on Growth](#)

[12/22/15 Brighter Setup for 2016; Upgrade to Buy](#)

[11/8/15 A Samba Reset](#)

[10/26/15 The Duke of North Carolina](#)

[8/10/15 Targeting a Samba Surprise](#)

[5/5/15 Even More Cash Coming](#)

What are the key updates for DUK?

Regulated:

- **Finding a path to low risk coal ash classification:** On June 30th the North Carolina legislation passed House Bill (HB) 630 by a vote of 82-32 which would result in a lower risk classification for some of Duke Energy's (DUK) coal ash pits. Specifically more basins could be classified as "low" risk rather than "intermediate" risk and be allowed to have 'cap-in-place' treatment rather than excavation. We view this development as a positive for DUK shares as investors had been growing increasingly concerned by the potential for significant rate inflation from more costly coal ash treatment (and in turn limited equity return on spend). The Governor has subsequently signed the bill into law.

The current asset retirement obligation is a probability-based assessment of what management estimates the clean-up/retirement costs will be on a discounted basis.

NC legislation could reduce the capex required for coal ash remediation, thus limiting bill inflation (and in turn limited equity return on spending).

Only approved capex for high-risk basins is included in Duke's plan today

- **SC rate case includes material rate inflation:** Duke Progress filed for a +\$79Mn revenue increase request with the Public Service Commission of South Carolina (PSCSC) with a **10.75% ROE** and 53% equity ratio. The majority of the request relates to new capital (67%) while O&M represents 25% of the step-up in revenue. The latest ROE datapoints in South Carolina are SCANA's (SCE&G) settlement in June 2015 (**10.5%**) and Duke's settlement in September 2013 (**10.2%**). Given the declines in interest rates and Duke's settlements in South Carolina and Indiana (see below), we expect pressure on the authorized ROE in this case.

DUK is requesting a +\$17/monthly increase (14.5%)

Timing and size of future rate cases across the Carolinas remains among the most substantial uncertainties in confidence towards the 4-6% EPS growth rate. We believe shares could trade up even if the lower end of the 4-6% growth rate is reiterated given low expectations.

- **\$1.4Bn Indiana grid modernization settlement approved without change:** The Indiana Utility Regulatory Commission (IURC) approved the grid modernization on June 29th without any further changes. As part of the agreement Duke reduced the cost of the plan to \$1.4Bn from \$1.827Bn, ~\$200Mn of which relates to deferring smart meter investments that Duke can re-propose at a later date. Additionally the ROE on trackers will be set at 10% rather than the 10.5% requested (no change to ratebase at 10.5%).

- **Drawing closer to the finish line with Piedmont:** Duke filed settlements with intervenors in June with the North Carolina Utilities Commission (NCUC) in the pending Piedmont acquisition. Parties include the NCUC Staff, consumer groups, and environmental parties. Hearings on the proposed merger are set for July 18th and management still is confident that it can close the transaction by year-end. Duke completed the equity component of the financing on March 7th when it closed the forward sale of 10.64Mn shares at \$72Mn, raising gross proceeds of \$766Mn; this is likely at the top-end of the \$500-\$750Mn after fees. Duke plans to finance the balance of the transaction with holding company debt.

DUK and PNY have reached settlements with various parties in North Carolina – the last remaining state left to opine on the proposed transaction.

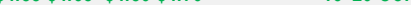

Commercial/Unregulated:

- **Getting closer to an international exit:** The last update from management was that they opened a dataroom in late March and was hopeful that it could provide more updates soon. We continue to perceive a sense of urgency in the process (1) with Petrobras stating that it intends to divest its own local generation assets [i.e. avoid competition] and (2) a desire to complete the deal by year-end. The improvement in foreign exchange rates should help improve the prospects for an attractive price but we still expect meaningful dilution (~\$0.20/sh).
- **Beyond Piedmont, management discusses other potential opportunities:** As management gets closer to resolution for the Piedmont acquisition and the discussed international sale, we see management focusing on growing its natural gas platform. Management has stated that it is looking for assets with (1) minimal/no commodity exposure; (2) long remaining contract life with high quality counterparty; (3) attractive valuation from a distressed owner in need of liquidity. This is consistent with comments from companies including NextEra Energy and Southern Company. Duke has continually stated that acquiring Piedmont was the first step in forming the 'core' of its gas business and we expect management to be active going forward.

EPS Estimates

Below we present our latest EPS estimates which excludes Piedmont and includes international. EPS accretion from Piedmont is expected to be \$0.12-\$0.15 through 2020E which could contribute 50bp to the EPS CAGR. Along with in-service of the Atlantic Coast Pipeline (ACP), we see the longer-term picture for DUK as brighter in comparison to the near-term potential for dilution from any Latin American divestiture.

Figure 112: Duke Adjusted EPS Estimates

Duke Energy EPS	2013A	2014A	2015A	2016E	2017E	2018E	2019E	
UBS Estimates	\$4.35	\$4.55	\$4.54	\$4.65	\$4.78	\$5.01	\$5.22	
<i>UBSe International</i>	\$0.60	\$0.61	\$0.32	\$0.31	\$0.30	\$0.28	\$0.28	
Prior UBS Estimates	\$4.35	\$4.55	\$4.54	\$4.65	\$4.78	\$5.01	\$5.22	
Consensus			\$4.54	\$4.59	\$4.75	\$4.99	\$5.13	
Guidance			\$4.55-\$4.65	\$4.50-\$4.70		16-'20 Core	4-6%	
UBSE 2016-2019 Core CAGR (ex-international and ex-PNY)				\$4.34				4.4%
UBSE 2016-2019 Core CAGR (w/o international and with PNY)				\$4.34				5.2%

Source: Company Filings, FactSet, and UBS Estimates

Valuation: Increase Price Target to \$93 from \$86

Our valuation is based on a 2018E P/E methodology with a 5% premium on EPS adjusted for our estimate of the international (Lat Am) divestiture and accretion from the pending Piedmont transaction. The \$7/sh increase in our price target is driven by the rally in US utilities with the peer multiple expanding to ~18.0x from ~16.7x in early May when we last reviewed Duke's valuation.

The 1.5x increase in utility valuations since our last MtM drives our price target up 9%.

Figure 113: Updated Duke Energy Valuation

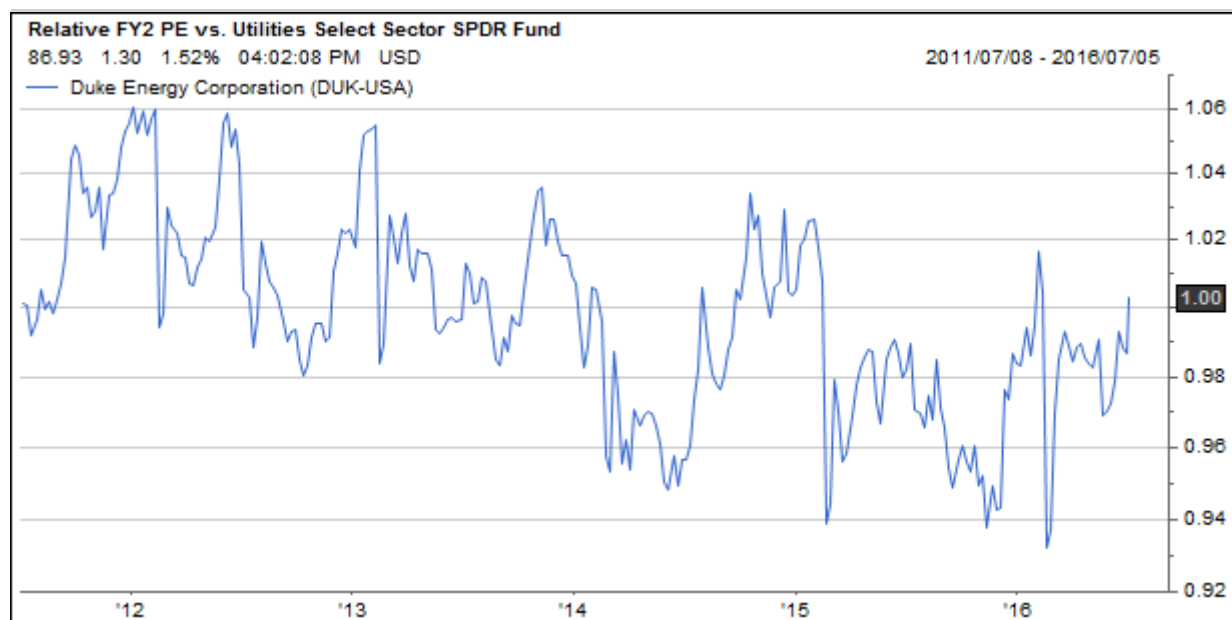
Duke Energy Valuation: P/E Derived on 2018 EPS					
Downside Case		Base Case		Upside Case	
2018 EPS	\$5.01	2018 EPS	\$5.01	2018 EPS	\$5.01
Minus: Lat Am Dilution	(\$0.27)	Minus: Lat Am Dilution	(\$0.24)	Minus: Lat Am Dilution	(\$0.19)
Plus: Piedmont Accretion	\$0.09	Plus: Piedmont Accretion	\$0.12	Plus: Piedmont Accretion	\$0.15
Total	\$4.84	Total	\$4.89	Total	\$4.98
P/E Multiple	17.0x	P/E Multiple	18.0x	P/E Multiple	19.0x
Premium/(Discount)	-5%	Premium/(Discount)	5%	Premium/(Discount)	10.0%
Value	\$78.00	Value	\$93.00	Value	\$104.00

Source: Company Filings, FactSet, and UBS Estimates

Can it be a premium story? Yes. We think Duke could return to a premium following several years of a re-rating lower given the volatility associated with the LatAm business (between F/X and hydrology). We emphasize with a 1-year forward view that Street will increasingly shift out to 2019E/2020E EPS, which bodes relatively *better* for Duke given the in-service timing of the Atlantic Coast Pipeline among other assets as well as lumpy nature of ratecase timing in the Carolinas.

We expect EPS growth will be trending towards the higher end of its 4-6% seemingly YoY later in the decade.

Figure 114: DUK Relative FY2 P/E Valuation



Source: FactSet

Dynegy Inc.

Following the latest capacity auctions the attention is now on the potential asset sales that management has discussed and the synergy update for Engie. We caution that sales prices could disappoint on a \$/kW basis for CA and NY.

We forecast Dynegy reporting 2Q16 adjusted EBITDA of **\$177Mn**, behind Street expectations (\$242Mn). We flag 2Q estimates reflect the first year of full year contributions from the prior ECP and Duke acquisitions. We see prices trending lower YoY primarily from lower dark spreads as well as milder Northeast sparks.

Look for weaker 2Q results

Figure 115: DYN 2Q16E Adj EBITDA Walk

Dynegy (\$Mn)	2Q16E	2Q15A	YoY	Notes
Consensus EBITDA	\$242			
Adj. EBITDA UBSe	177	193		
Corp & Other	(30)	(33)	3	Similar trend of ~\$30Mn, slightly higher YoY
IPH	5	5	-	Energy Margins offset by improving Capacity
CoalCo	20	19	1	Energy Margins offset by improving Capacity
GasCo	182	202	(20)	Lower Spark Spreads & Hedges Rolling

Source: Company reports, ThomsonReuters, UBS estimates

Updated EBITDA Estimates

We reflect the latest commodity MtM outlook, seeing estimates at the bottom-end of the range for 2016E. We currently estimate \$3.6Bn of cumulative 2016-2018E EBITDA versus the \$3.9Bn 2016E-2018E guidance provided at the 2015 Analyst Day last summer. Our estimates are tweaked higher on account of recent MtM improvements, consistent with recent share price recovery. We offset this with a negative impact from a ~350MW outage at one of the Hanging Rock CCGT units as well as the assumed retirement of the Coletto Creek asset in Texas.

Figure 116: Pro-Forma Forward EBITDA Estimates for DYN

Dynegy EBITDA Breakdown (UBSe)	2014A	2015A	2016E	2017E	2018E	2019E
Midwest	92	53	110	105	147	115
West	62	80	61	16	26	20
Northeast	187	163	141	135	154	155
Illinois Power Holdings	78	76	74	159	169	128
Duke Midwest	0	240	298	220	300	222
Energy Capital Partners	0	253	332	373	445	392
PRIDE Reloaded & Other Synergies	0	115	233	265	290	290
Consolidated G&A and Other	(72)	(130)	(130)	(130)	(130)	(130)
Recurring Adjusted EBITDA	347	850	1,119	1,143	1,401	1,192
Previous		850	1,119	1,162	1,388	1,175
Consensus (6/15/2016)	\$364	\$880	\$1,101	\$1,263	\$1,398	\$1,138
Engie JV (100%)			\$451	\$453	\$566	\$486
Mgmt Guidance: Adj EBITDA	\$300-\$350	\$825-\$925	\$1.0-\$1.2Bn	~\$1,300	~\$1,300	
Capital Spending	-\$160	-\$285				
Cash Interest	-\$145	-\$425				
Other Cash Impacts	\$15	-\$15				
Free Cash Flows	\$10-\$60	\$140-\$240	\$200-\$400	~\$500	~\$500	

Source: Company reports, USB estimates

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

[6/16/16: Simplifying the Art of the Deal](#)
[6/9/16: Commodity Rally Priced In: Downgrade to Neutral](#)
[5/4/16: Taking a Seat at the Negotiating Table](#)
[4/14/16: Painting the Path Forward](#)
[2/26/16: Bringing The Band Back Together](#)
[2/25/16: Slow Start to 2016 Dings Outlook](#)
[5/11/15: Muted Expectations](#)
[9/18/15: Capacity Auction Delivers](#)
[8/7/15: Repurchases Are Just The Right Medicine](#)

What are the key updates for DYN?

- **Getting clarity on reforms in MISO:** We look for datapoints on the MISO reform process, which is scheduled to provide updated throughout July and August ahead of a late August filing before the FERC for capacity auction reforms. Our expectations for pricing improvement in the market remain modest and caution that the scenario analysis released by MISO and the market monitor may not fully materialize. Bottom line, we perceive wider skepticism from a variety of constituents including management here. The focus will remain on finding a way to export more capacity into PJM.
- **IPH restructuring underway:** Mgmt remains in negotiations with creditors. Given anticipated retirements, DYN is keen to restructure debt proactively ahead of its maturity in 2017. The \$825 Mn trades at \$320Mn in market value. A further nuance could include the contribution of *existing* assets to IPH ring-fence for the debt following previously management statements but it is unclear how much value that would provide (seemingly minimal). Dynegy's 1Q16 presentation substantially reduced FCF expectations at this subsidiary given the potential re-assignment of value at this subsidiary back to Dynegy given the marketing arrangements in place.

What's the market value today?

The IPH bonds imply a pricey ~\$125/kW for the remaining (2) coal plants assuming the Newton plant is retired. We would not expect management to offer to take in the structure at the current valuation, seeing limited value, particularly without the marketing enterprise behind DYN.

Addressing IPH remains the top priority for this year

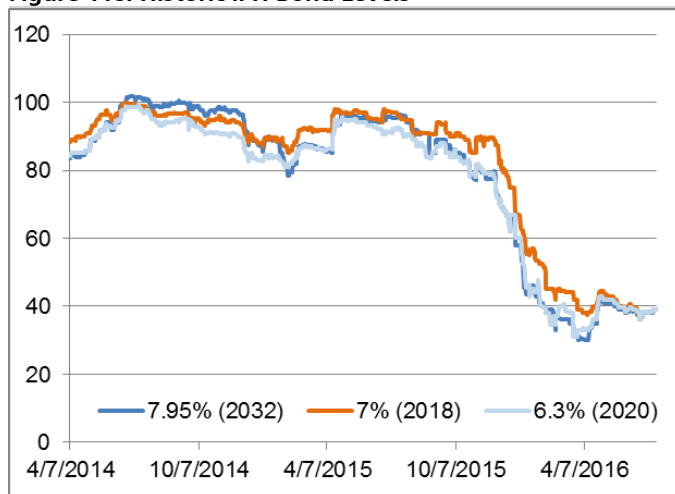
Debt is trading at ~40¢ of late, or ~\$320Mn in market value vs. \$825Mn par value

Figure 117: FMV of IPH Bonds (\$Mn)

Analysis of IPH Bond Valuation (\$Mn)			
Notes	Fair Mkt Value	Book Value	
2032	107.3	275.0	39%
2018	117.0	300.0	39%
2020	97.5	250.0	39%
	<u>321.8</u>	<u>825.0</u>	39%

Source: FactSet

Figure 118: Historic IPH Bond Levels



Source: FactSet

But is there value at the subsidiary? Unlikely given the debt

While we do not see value today in the segment even at the \$320Mn mark-to-market of debt, we think management might consider offering lenders a deal to exchange their debt for either parent obligations or tender for cash at a discount to their existing value. We note the debt has few alternatives on a stand-alone basis, with the remaining assets operating at seemingly breakeven FCF levels (at best).

More asset sales have been discussed by management:

DYN appears poised to divest additional assets in effort to continue to reduce leverage and re-allocate resources

- **Looking hard at California still to divest:** Management continues to evaluate options around a contemplated divestment of its West coast portfolio. We see the bulk of the value as accruing to the portfolio via its Moss Landing CCGT, with its remaining assets (Morro, Oakland, and Moss 6&7 as primarily real estate/salvage value). We expect Moss 6&7 to be retired at year-end at the conclusion of its existing capacity contract (with just one year left on its operating life due to Once-Through-Cooling [OTC] limitations anyways).

The unfavorable alternative proposed decision of the latest PG&E GTS&S case added \$10-15 Mn/yr in costs to the portfolio, substantially reducing the EBITDA and FCF profile of its assets. It appears to have added nearly ~\$1/MMBtu, driving rates up to nearly ~\$1.35/MMBtu for delivery on the PG&E gas LDC to the plant). The uptick in rates could practically eliminate all value of the plant as we perceive relatively limited dispatch should the proposed rate structure be adopted (with the ~\$200 Mn NPV swing in value potentially equal to the plant overall value when applying value of \$100-200/kW to the operating business and marginal value for the three legacy peakers). *Separately we continue to see the potential for a well-above inflation rate increase proposed on customers as a key risk to PG&E.* Status quo, we see California as worth ~\$1/sh to the overall value of DYN.

We look for sale price expectations to continue to trend lower as IPPs transact in the lower spark and capacity price environment. We include our latest expectations on this sale following the negative PG&E GT&S auction outcome.

We see a risk the Dynegy portfolio could garner some attention as a meaningfully negative implied \$/kW value, as well as a headline low value for the core of the portfolio, the 1GW CCGT, Moss 1&2, potentially at ~\$100/kW or lower.

Figure 119: California Portfolio Potential Value

Dynegy California Portfolio Potential Transaction Value							
Asset	Location	Fuel	MW	\$/kW	Value (\$Mn)	EBITDA	Implied EV/EBITDA
Moss Landing							
Units 1-2	Monterey County	Gas CCGT	1,020	80	\$82	\$8	9.9x
Units 6-7	Monterey County	Gas	1,509	-	-	N/A	N/A
Oakland	Oakland	Oil	165	30	5	N/A	N/A
Morro Bay*	Morro Bay	N/A	650	8	5	N/A	N/A
* Transmission Capacity		Total	2,694	34	\$92		
		Total per Sh			\$0.58		
Est. Rate of Delivered Gas ↑ Potential W./ GTS Case: \$1/Mmi NPV ~\$200Mn							

Source: Company Filings and UBS Estimates

We include our best estimate of the EBITDA profile of this asset under the gas tariff.

What are the new economics of the Moss Landing 1&2 CCGT?

Figure 120: Moss Landing 1&2 – Estimated new EBITDA profile

CCGT - Moss Landing 1&2	2014A	2015A	2016E	2017E	2018E
Revenue	187	125	91	94	96
Moss Landing CC	4.1	3.4	2.9	3.1	3.1
Capacity	1,020	1,020	1,020	1,020	1,020
Capacity Factor	46%	38%	33%	35%	35%
NP15 Onpeak (\$/MWh)	47	40	34	37	38
PG&E LDC Adder (\$/Mmbtu)				0.69	0.69
PG&E Citygate (\$/Mmbtu)	5	3	3	4	4
Spark Spread - NP15	10	14	8	2	3
Carbon Cost (\$/t)	12	12	12	12	12
Gross Margin (Spark)	42	47	24	6	10
Premium to Peak	10%	10%	10%	10%	10%
Fuel Cost	145	77	67	88	86
O&M	26	26	26	26	26
O&M (\$/MWh)	5	5	5	5	5
O&M (\$/kW-yr)	25	25	25	25	25
Energy EBITDA	16	22	-1	-19	-15
Capacity on 1&2	693	750	750	750	1020
Capacity/Tolling Payments	9	17	17	17	24
Tolling Agreements (\$/KW-yr)	14	23	23	23	23
EBITDA with Capacity	26	39	16	-2	8

Source: Company reports and UBS estimates

What about New York: Independence prospects reduced: On the heels of its Engie deal, we continue to look for datapoints on the potential sale of its 1.2GW Independence CCGT. While expectations had been climbing higher towards \$600/kW or better, the question is how substantial upstate New York power market expectations have been negatively impacted by the latest offer from the NY PSC to extend 'Zero Emission Credits' (ZECs) to nuclear units upstate. This has been the key wildcard to not just capacity markets (where we estimate a ~\$30Mn/yr swing in future EBITDA expectations) as well as power price expectations (alongside RGGI price expectations, which also eventually are reflected in the power price as well). Further, with the NY PSC poised to provide an updated view by month on its latest track in REV on Renewables, we suspect RPS datapoints could also moderate expectations. That said, Dynegy knew of these potential forthcoming potential pressures in pursuing the sale and see the calculated decision to de-emphasize this market as illustrative of these wider concerns. We estimate ~\$90-100 Mn in annualized EBITDA from this asset, suggesting ~\$600/kW is between a 7-8x EV/EBITDA multiple.

Similar to California, management has stated that maintaining a regulatory presence in a state required a portfolio to justify the cost and management effort

[Further details on the NY ZEC proposal are available here.](#)

- **What else? PJM peakers.** We believe several could be on the block too as management appears keen to capitalize on more robust capacity and spark spreads of late. While unclear precisely which units, we generally believe the PJM market is approaching a 'top' of its respective cycle. While it would appear strategically challenging to sell-down gas assets amidst its efforts to reposition the portfolio, it would appear more consistent that it is resulting in additional gas purchases, effectively replacing its portfolio at better value elsewhere.

Looking for synergies update upon close; this includes coal retirements

We see little palatability for management to continue to operate assets that generate negative FCF; specifically, this includes its coal portfolio. Following years of distress in the power markets, we perceive an accelerated retirement. Further, we think this mantra would leave little latitude to maintain the Coletto Coal plant in Texas; thus we believe DYN might prove among the first coal operators to shut coal in the state. We do not expect synergy updates with 2Q16, but would expect an announcement in tandem with the deal close, potentially with 3Q16 results (~October 1st).

Figure 121: DYN FCF Profile

Dynegy Free Cash Flow Analysis	2014A	2015A	2016E	2017E	2018E	2019E	2020E
Adjusted EBITDA	957	840	1,119	1,143	1,401	1,193	1,117
Less: Interest Expense	(147)	(546)	(505)	(505)	(505)	(505)	(505)
Less: Taxes	No Cash Taxes Through At Least 2018E					(123)	(93)
FCF Pre-Capex (Proxy for FFO)	810	294	614	638	896	565	518
Less: Capital Expenditures	(123)	(255)	(335)	(274)	(369)	(269)	(269)
Plus/Minus: Other	27	5	(20)	(3)	(3)	(3)	(3)
Free Cash Flow	714	45	259	361	524	293	246
Guidance	\$10-\$60	\$140-\$240	\$200-\$400	~\$500	~\$500		
Debt Profile (incl. ST Debt Balance)	\$7,106	\$7,289	\$7,289	\$7,289	\$7,289	\$7,289	\$7,289
Cash	\$880	\$505	\$854	\$1,226	\$1,580	\$1,724	\$1,792
Net Debt	\$6,226	\$6,784	\$6,435	\$6,063	\$5,709	\$5,565	\$5,497
Net Debt / EBITDA	6.5x	8.1x	5.7x	5.3x	4.1x	4.7x	4.9x
FFO / Gross Debt	11%	4%	8%	9%	12%	8%	7%
FCF Yield	34.0%	2.1%	12.3%	17.2%	24.9%	13.9%	11.7%

Source: Company Filings and UBS Estimates

Valuation: Maintaining \$22 Price Target

Our valuation continues to be based on a 2018E sum-of-the-parts methodology. The focus will be on the IPH subsidiary and to what extent management could provide value to bondholders for any forthcoming exchange to execute on a deal. Our valuation reflects retirement of Coletto Creek in 2017+ as well as unit outage at Hanging Rock.

Figure 122: Maintain Dynegy Valuation: The Engie Mini-Model Uplift is Included

Dynegy Inc - 2018E	EBITDA	EV / EBITDA Multiples			Low	Base	High
		Low	Base	High			
Base IPP Multiple =			7.0x				
Legacy Dynegy	327	4.0x	6.0x	7.0x	\$1,310	\$1,965	\$2,292
Illinois Power Holdings (IPH)	169	3.0x	5.0x	6.0x	\$506	\$844	\$1,013
Duke Midwest	300	6.0x	7.0x	8.0x	\$1,803	\$2,103	\$2,404
EquiPower (~ISO-NE Portfolio)	445	6.0x	7.0x	8.0x	\$2,668	\$3,113	\$3,557
Less: West Peaking	(18)	5.0x	6.0x	7.0x	(\$91)	(\$109)	(\$127)
Synergies, Corp. Overhead, & Other	160	5.0x	6.0x	7.0x	\$800	\$960	\$1,120
Engie	566	6.0x	7.0x	8.0x	\$3,396	\$3,962	\$4,528
Total Unregulated EV	1,967	5.3x	6.5x	7.5x	\$10,393	\$12,838	\$14,788
Net Debt (12/31/15)							
Dynegy Inc.					\$6,380	\$6,380	\$6,380
Illinois Power Holdings (IPH)					\$825	\$825	\$825
Engie-Related Financing					\$2,000	\$2,750	\$3,150
Plus: NPV of West Peaking					(\$25)	(\$45)	(\$50)
Cash and Equivalents					(\$253)	(\$505)	(\$880)
Total Net Debt					\$8,928	\$9,405	\$9,425
Net Debt / Adjusted EBITDA		4.5x	4.8x	4.8x			
Removing Net Equity Drag of IPH					\$319	\$0	\$0
Total Equity Value					\$1,784	\$3,433	\$5,362
Implied FCF Yield		20%	11%	7%			
Estimated Shares Outstanding (Mn)		158	158	158			
Dynegy Valuation					\$11.00	\$22.00	\$34.00
Upside/(Downside)					-35%	31%	102%
Price Target Gross EV/EBITDA Multiple		5.3x	6.5x	7.5x			
Current Price Implied Gross EV/EBITDA Multiple		5.5x	5.8x	5.8x			
Dilution Implied from Consolidating IPH		-\$2.01	\$0.12	\$1.19			

DYN Engie Portfolio	EBITDA	EV / EBITDA Multiples			Low	Base	High
		Low	Base	High			
ISO-NE	210	6.0x	7.0x	8.0x	1260	1470	1680
PJM	171	6.0x	7.0x	8.0x	1026	1197	1368
ERCOT	185	6.0x	7.0x	8.0x	1110	1295	1480
Total Unregulated EV	566	6.0x	7.0x	8.0x	\$3,396	\$3,962	\$4,528
Pro-Forma Financing							
Secured Debt					(2,000)	(2,000)	(2,000)
Mandatory Convert ("Tangible Equity Units")					(400)	(400)	(400)
DYN Equity Sale to ECP					(150)	(150)	(150)
DYN Forward Capacity Sale					(200)	(200)	(200)
DYN Cash/Borrowing Contributed					(550)	(550)	(550)
Total Debt+DYN Equity					(3,300)	(3,300)	(3,300)
Total Equity Value					\$96	\$662	\$1,228
DYN's Equity Value (65%)	100%				\$96	\$662	\$1,228
Shares Outstanding					137	137	137
Dynegy Valuation					\$1.00	\$5.00	\$9.00

Source: Company filings, FactSet, UBS estimates

Edison International

Potential for SONGs case reopening remains one of the key questions in the near term but we see risk of a prolonged outcome as relatively limited. No substantial surprises are expected in the quarter and we see a relatively in line earnings number.

Key Drivers: 31 cent tax benefit last year makes YoY comp challenging but we believe productivity/financing benefits and ratebase growth provide some mitigation in the quarter.

Wildcard Factors: Earnings Ex-Songs remains somewhat-untested territory, while negative parent items proved more influential than our expectations last quarter. We think tax shifts due to the Tax Accounting Memorandum Account (TAMA) could shift the quarter further.

Figure 123: EIX 2016E UBS Quarterly Estimates

	Ex-SONGS EPS Distribution				Total
	Q1	Q2	Q3	Q4	
2009 EPS distribution	24%	24%	34%	18%	
2015 EPS distribution	22%	28%	28%	21%	
Average Ex-SONGS EPS Distribution	23%	26%	31%	20%	
UBSe 2016 Estimate Distribution					
Ratebase	0.88	1.00	1.18	0.76	3.82
Reduce ratebase for bonus depn		(0.01)	(0.01)	(0.02)	(0.05)
Add Pole Loading ratebase		0.02	0.03	0.04	0.09
O&M reduction		0.04	0.05	0.07	0.17
Edison Energy Group		-	-	-	-
Energy efficiency		-	-	0.05	0.05
Parent & other	(0.05)	(0.05)	(0.05)	(0.04)	(0.18)
UBSe 2016 (basic)	0.83	1.01	1.20	0.86	3.90
UBSe 2016 (diluted)	0.82	1.00	1.19	0.85	3.88
Consensus		1.01	1.19	0.87	3.89
Core Basic EPS Guidance					3.81-4.01

Source: UBS estimates, company filings, FactSet

The next table illustrates our estimates for year-over-year quarterly EPS impacts.

Figure 124: EIX 2016E UBS Quarterly Estimates

2016 vs 2015 Delta (diluted)	Q1	Q2	Q3	Q4	Total
2015A (diluted)	0.89	1.15	1.15	0.87	4.08
Ratebase growth (w/Pole Loading)	0.04	0.07	0.09	0.05	0.28
Productivity and financing benefits in 2016		0.04	0.05	0.03	0.17
O&M & Severance	(0.04)	0.02	0.03	(0.09)	(0.08)
Change in uncertain tax positions		(0.31)			(0.31)
Higher utility taxes under TAMA	(0.02)	-	(0.11)	(0.05)	(0.18)
Generator settlements in 2015		0.03			0.03
Property tax refund in 2015		0.01			0.01
Parent & Other	(0.05)	(0.02)	(0.02)	0.04	(0.05)
2016E UBSe, diluted)	0.82	1.00	1.19	0.86	3.88

Source: UBS estimates, company filings, FactSet

What are the Key Issues for EIX?

SONGS: Will the filing reopen?

TURN and ORA Filed Response Briefs

TURN and ORA filed intervenor testimony as part of the ongoing inquiry as to whether to formally [reopen the record](#) into the 2014 San Onofre Nuclear Generating Station cost recovery settlement. The most punitive position came from TURN, which advocates 50%+ of \$2Bn ratebase should be removed in the event the case is not reopened given their position that the premature retirement was attributable to imprudence at SCE. Specifically, TURN suggests the burden falls on SCE to demonstrate the defective steam generators (responsible for the shutdown) were *not* the result of imprudence on the company's part. ORA focused more narrowly on the difference between its litigated position and settlement which would imply a ~\$383M ratepayer refund (likely tax deductible). Both intervenors suggested the \$25M allocated to Greenhouse Gas research at UC should be refunded and TURN further advocated for ~\$87M refund to account for the time when SONGS could run without installing the defective equipment (effectively implementing the PD). **Reading between the lines: neither party overly emphasizes full re-opening**

TURN's filing includes extensive sections on *alternatives* to re-opening the settlement, further ORA simply asks for its full litigated position. We see expedited resolution as a wider positive. The [alternative](#) appears to be full litigation of phase 3, and finalization of Phases 1 & 2 per the already established records. Note: No settlements would be possible if SONGS is fully re-opened

Was the settlement reached following commission standards? The intervenors are focused on the argument that ex parte discussions disadvantaged their bargaining position which shifted the dynamics of the settlement negotiations. The key point of the arguments hinges on the retraction of support from the settlement by both TURN and ORA after ex parte revelations and that it disadvantaged them, but the commission has already noted the more favourable outcome, as we discussed in our [previous note](#) vs. prior positions.

CPUC Reforms: More to Come

Governor Brown and Senators Jerry Hill (D) and Mark Leno (D) announced a CPUC reform package on 6/27/16, which will be introduced to the Legislature in the following months. The plan appears largely supportive of the CPUC's governing power for utilities, allowing for a closer focus

Some of the key points include:

- Governance: Move a number of transportation-related responsibilities to the California State Transportation Agency for the purpose of helping the CPUC's focus elsewhere.
- Governance: several initiatives to help hiring and employee retention and leverage outside work
- Governance: Allow Alternative Proposed Decisions at any point before the vote (as opposed to simultaneously with the main PD)

- Accountability: barring former utility executives from serving at CPUC for 2 years and allowing any California agency to participate without official party status
- Accountability: Authorization for the California Attorney General to bring legal charges against CPUC employee that violates ex parte communication requirements.
- Transparency: A number of measures related to ex parte communications. Failure to log communications online promptly will result in a penalty (enforced by CPUC or AG), but meetings with members of the public are unrestricted
- Transparency: CPUC lobbyists will be required to register as such
- Transparency: allow more ratesetting deliberations, even if no hearing has been held
- Oversight/Safety: Creation of an “Ethics Ombudsperson” as a point of contact
- Oversight/Safety: Expedite SONGS spent fuel relocation

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

[8/7/16 Same SONGS, Different Tune](#)

[3/4/16 The ‘How Can Utilities Be So Great Again?’ Conference Deluge \(p. 27\)](#)

[2/24/16 Taking the Pole Position](#)

[11/30/15 Accounting for Tax Benefits](#)

[11/5/15 At the 1-Yard Line: A Mostly Final Ratecase Order](#)

[10/28/15 Looking Through the Transmission Delays](#)

[9/21/15 Rebasing the Power Trade](#)

[8/10/15 Less Settled, But Still Intact](#)

[8/3/15 SONGS Enters New Stanza with \\$7.6B Arbitration](#)

Empire District Electric Company

EDE and Algonquin have made important steps towards completing their pending merger with approval in Oklahoma and a settlement in Arkansas. The timeline in Kansas and Missouri is a bit longer-dated but we expect the companies to continue working with stakeholders to try and proactively address any issues.

EDE does not intend to host an earnings calls at this time.

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

[2/23/16 Searching For Clues in Regulated M&A](#)

[2/10/16 Acquiring an Empire](#)

[12/13/15 Evaluating Alternatives](#)

[11/3/16 Ratecase Double Header](#)

[9/28/15 Approaching Ratecase Season](#)

[8/11/15 Show Me The Ratecase](#)

[5/11/15 Stuck in a Growth Quagmire](#)

[2/10/15 Structurally Lagging?](#)

What are the key updates for EDE?

- **What is the status of the pending Algonquin transaction?** We spoke with management regarding the current status of their merger with Algonquin Power and Utilities (AQN). As it stands, the Oklahoma Corporation Commission (OCC) and the FERC has approved the merger, while a decision is still pending in Kansas, Missouri and Arkansas but a settlement was filed in Arkansas in late June. We do not see any significant obstacles left for Empire to overcome as management commented Algonquin has been proactive in addressing regulators' concerns the larger issues off the table in their discussions with regulators.

EDE has guided to a 1Q16 close while Algonquin has been more precise in stating it expects a January 2017 close.

We summarize the status below:

- **FERC:** Approval received
- **EDE Shareholder Vote:** Approval received
- **Oklahoma:** Approval received
- **Other Federal Approvals:** Pending but management does not anticipate any roadblocks here
- **Kansas:** Late November/Early December hearing
 - 300-Day statutory calendar implies resolution approximately in mid-January
- **Arkansas:** Settlement filed in June with related conference
 - Stipulation precludes the combined company from filing a rate case until 12-months post the merger closing but there is an opportunity to request recovery for Riverton 12 via a rider
- **Missouri:** Discovery process underway

With respect to financing the \$2.4B deal, Algonquin has secured C\$1.15B convertible debentures, is assuming \$900M in debt and only has to complete the \$600M private placement.

- **Reaching settlement in MO rate case with 9.5-9.9% ROE range:** On June 20th EDE filed a unanimous settlement with the Missouri Public Service Commission (PSC) with a +\$20Mn revenue increase in its pending rate case which is primarily related to the Riverton CC project. The settlement includes an ROE range of 9.5-9.9% compared with EDE's 9.9% ROE request and the PSC Staff's recommendation for a 9.75% ROE. A final Missouri PSC decision is expected by September when management expects to have new rates effective.

The ROE range has read-throughs for AEE and GXP which each have rate case requests pending with the MO PSC with 9.9% requests.

Figure 125: 2016 EDE Ratecase Filing

Rate Case Revenue Requirement Drivers: ER-2016-0023		
Requested Items	Revenue Req.	% of Total
Riverton Unit 12 CC Conversion	27.4	82.0%
Asbury True-Up	2.1	6.3%
Effect of Depreciation Study	-1.0	-3.0%
ROE / Capital Structure	-3.2	-9.6%
Other Normal Plant Additions	6.0	18.0%
Administrative Costs	2.1	6.3%
Total Increase Request	33.4	
Settlement Increase	20.4	
9.9% Requested ROE; 9.5-9.9% Settlement ROE		

Source: Company filings

Figure 126: 2014 EDE Ratecase Filing

Rate Case Revenue Requirement Drivers: ER-2014-0351		
Requested Items	Revenue Req.	% 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 Increase Request	24.3	
Approved Settlement Increase	17.1	
10.15% Requested ROE		

Source: Company filings

What is the true potential of ratebase growth?

- **Algonquin indicates that EDE ratebase growth could accelerate above 4% but timing is likely longer-dated:** In Algonquin's March 2015 presentation, the company disclosed their outlook for ratebase growth. Among the four main opportunity areas are:
 - Active pursuit of coal replacement/displacement with new ratebase renewables
 - Replacement of energy sourced through PPA with ratebased generation
 - Further conversion of coal assets to natural gas co-generation
 - Joint IT infrastructure investments

Aside from the fourth item relating to IT spending we view the opportunity areas as longer-dated and beyond the scope of the current investment horizon. For example the first PPA to expire is in 2025.

We agree with AQN that there are ratebase growth opportunities related to environmental policies but do not expect any material changes to the capex forecast before 2020

Valuation: Maintain Price Target

Valuation is based on the full \$34 takeout price. EDE has been trading very close to this level indicating that investors are ascribing a high probability of the pending transaction closing.

Entergy Corp.

We expect management to report 2Q adjusted EPS of **\$0.73**, meaningfully behind the Street (\$1.09), but see prospects for a meaningful swing from tax items. As such, we think the headline number has a high probability of substantially exceeding our estimate (and even Street) considering the magnitude of the FY tax benefits guided (~\$0.30+) as mgmt has disclosed this brings mgmt back from the lower end of 2016 at least towards the midpoint if not the high end. Aside this detail the question on 2Q results could revolve around the protracted Indian Point 2 outage- and prospects for more structural unit recovery.

2Q could be a bit weak – but expect tax items could save it

Figure 127: ETR 2Q16E Earnings Walk

Entergy Corp 2Q16 Earnings Walk	EPS
2Q15A Adjusted EPS	\$0.83
Entergy Wholesale Commodities (EWC)	
Refueling and Outage Days Comparison: IP2 Outage vs Pilgrim	(\$0.17)
RISEC: Sold 12/17/15	\$0.01
Net Revenue M&M	(\$0.07)
Non-Fuel O&M: Pension & OPEB Benefits	\$0.03
Decommissioning Expense	(\$0.01)
Other Income	(\$0.03)
Depreciation, interest, income taxes, & other	(\$0.08)
Utilities	
Weather vs Normal in 2Q15	\$0.02
Weather vs Normal in 2Q16	\$0.05
Sales (1.9% Growth assumption: 1H16 weighted)	\$0.04
Rate Case + DCRF Benefit (TX and AR) - Mostly Union	\$0.15
Non-Fuel O&M	\$0.05
Depreciation	(\$0.06)
Parent & Other	(\$0.03)
Income Taxes	\$0.00
2Q16E Adjusted EPS	\$0.73
2Q16 Consensus	\$1.09
2016 UBSe EPS	\$4.86
2016 Consensus	\$5.12
2016 Guidance	4.95-5.75

Source: Company filings, FactSet, UBS estimates

Ratebase Profile Still Married to Load Growth

Path to distribution growth focus could have bumps along the way

At its 6/9 Analyst Day Entergy provided its Utility, Parent, & Other (UP&O) 2016E-2020E EPS CAGR of 5-7% although using the annual midpoint of the years implies 5.6% annual growth, in the bottom-end of the range. This earnings growth is supported by 5-7% rate base growth expectations (7.2% spot estimate) with transmission and distribution capital spending growing later in the decade as generation spending tail-off in the current plan. Management lowered its sales growth expectations again and now forecasts 1.5-2.0% from 2015-2020E versus 1.9% YoY in 2016E. Approximately 20% of the generation capex is designed to meet load growth (\$1.4Bn out of the \$16Bn capex plan) and in a scenario where only half of this generation growth materializes then the rate base CAGR could be 70bp lower. Furthermore, additional transmission &

distribution (T&D) upgrades could be removed from the base plan if growth does not arrive as planned. Bottom line we view the shift towards a T&D spending focus as a positive but the ratebase story is still linked to sales growth, a factor that has continued to weigh on investor confidence.

Nuclear costs largest uncertainty: will it earn its authorized level?

Management was confident that it could mitigate the “hundreds of millions” in Nuclear Sustainability Plan costs by reducing costs elsewhere and/or requesting rate relief for prudently incurred capital and O&M. This remains another key uncertainty in the story for the next five months. Further details are expected at EEI.

EWC still a drag but not properly captured in the stock

Few new details emerged about the unregulated EWC business at the Analyst Day but management guided to negative FCF from the business (seemingly hundreds of millions cumulatively from 2016-2020 including positive DOE litigation recovery) which could grow depending on the degree to which additional spending is required from the Sustainability plan. Although the merchant part of the story has declined, we continue to view it as a drag on value. Entergy has guided to \$7-\$10Mn EBITDA drag for its plants annually after the units shutdown (-\$20Mn in 2020E for Vermont Yankee, FitzPatrick, and Palisades) indicating that if Entergy closes all of its nuclear units (Indian Point and Palisades) it could incur a -\$35Mn to -\$50Mn annual FCF drag.

What do we think of shares?

We saw ETR's recent Analyst Day as relatively more cautious; the near-term question remains what kind of compensation it will receive for Fitzpatrick. While rate base prospects appear to be intact with the latest capex roll forward, we see the specific EPS guidance would lend itself towards the lower end of its contemplated 5-7% 2016E-2020E CAGR. We think upsides to achieve the higher end would appear tied to successful execution of a gas reserves in ratebase effort (likely an uphill battle) in addition to being longer-dated within management's capex plan. Further, recovery of the 'several hundred millions' or more of regulated nuclear spending in unclear would also appear incremental (an incremental \$500 Mn of capex would equate to ~0.5% to the 5-year CAGR). We emphasize the underlying ratebase growth from 2016E-2020E implies a trend of 7.2% off 2016E, more consistent with mgmt's targets. The discrepancy between the EPS and ratebase guidance is unclear as we would expect that (1) an improving earned ROE trend would enable the company to out-earn the nominal ratebase growth trajectory [as mgmt. has previously put into its guidance] and (2) benefits of residential sales growth would further enhance the earnings profile in the absence of equity issuances.

We maintain our Sell rating on shares.

What is Fitzpatrick Worth?

Among the key near-term questions is just how much Entergy can sell this asset to Exelon as part of implementing the ZEC program. While we perceive that EXC did not have much of a choice as to purchasing ETR's plant or not in implementing a wider ZEC program in the state, we perceive limited value will ultimately be paid to ETR for the plant still. We estimate for our purposes ~\$100Mn initially, although this could prove too low. Mgmt remains focused on de-emphasizing merchant nuclear and this would be among the first significant nuclear transactions in some time. We also remind investors that the NDT fund in this instance is held with NYPA and would be transferred to ETR at close, and to EXC assuming sale. We note that the fund is currently fully-funded.

We emphasize the EPS CAGR at the midpoints of the guidance range indicates a 5.4% EPS growth rate vs. the 5-7% rate for Utility Parent & Other guided by management, albeit a baseline year is unclear.

Figure 128: Fitzpatrick DCF for Life of ZEC Program

FitzPatrick FCF Analysis	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Owned Capacity (MW)	838	838	838	838	838	838	838	838	838	838	838
Capacity Factor	98%	80%	98%	80%	98%	80%	98%	80%	98%	80%	98%
Generation (TWh)	7.2	5.9	7.2	5.9	7.2	5.9	7.2	5.9	7.2	5.9	7.2
Energy Revenue (\$MWh)	\$30.32	\$30.06	\$29.57	\$30.05	\$30.53	\$31.01	\$31.49	\$31.97	\$32.45	\$32.45	\$32.45
Capacity (\$MWh)	\$5.11	\$9.85	\$6.64	\$8.13	\$5.59	\$6.85	\$5.59	\$6.85	\$5.59	\$6.85	\$5.59
Total Market Revenue (\$MWh)	\$35.43	\$39.91	\$36.21	\$38.18	\$36.12	\$37.86	\$37.08	\$38.82	\$38.04	\$39.30	\$38.04
Net ZEC Value (\$MWh)	\$17.48	\$16.57	\$17.48	\$19.06	\$19.59	\$20.93	\$21.38	\$23.22	\$23.83	\$25.50	\$26.45
Total Revenue (\$MWh)	\$52.91	\$56.48	\$53.69	\$57.25	\$55.71	\$58.79	\$58.46	\$62.04	\$61.87	\$64.80	\$64.49
Estimated Cost (\$MWh)	\$43.54	\$43.54	\$43.54	\$43.54	\$43.54	\$43.54	\$43.54	\$43.54	\$43.54	\$43.54	\$43.54
Free Cash Flow (\$MWh)	\$9.37	\$12.94	\$10.15	\$13.71	\$12.17	\$15.25	\$14.92	\$18.50	\$18.33	\$21.26	\$20.95
Free Cash Flow (\$Mn)	\$67	\$76	\$73	\$80	\$88	\$90	\$107	\$109	\$132	\$125	\$151
ZEC FCF Improvement (\$Mn)	\$126	\$97	\$126	\$112	\$141	\$123	\$154	\$136	\$171	\$150	\$190
Total FCF (\$Mn)	\$1,553										
Discount Rate	13%										
Net Present Value (\$Mn)	\$609										
vs. Sale Price ??											
Net Value (\$Mn)	\$609										
Value per Share	\$0.69										

Source: Company reports and UBS estimates

The question is how a sale of Fitzpatrick would revise estimates? We expect this to be a positive removing the drag contemplated from its removal from service (~\$0.03) but also reduction in risk. We don't believe this would have a meaningful impact otherwise on EWC's efforts for nuclear spend forthcoming.

Utility:

- Five-year growth rate at 5-7% but midpoint points to bottom-half: Management predicts 5-7% rate base growth through 2020E which is based on transmission and distribution spending opportunities picking-up for generation capital investment towards the end of the decade. We estimate generation capex will likely peak in 2016E including the Union Station acquisition and is currently expected to decline to below \$80Mn in 2020E in the absence of new opportunities. In the current 2020E generation plan nuclear/baseline capex is the majority of spending (~\$500Mn) with only a small component dedicated to new build. The spending from 2016-2020E is designed to meet 4.0-4.5GW of new generation in 2020-2025E. The majority of the projected supply additions will be baseload CCGTs with peaking capacity representing the balance. 80% of capex spending is to replace aging infrastructure with only 20% of capex necessary to meet expected load growth. We elaborate in more details on each of the three spending components: generation, distribution, and transmission.

Reducing industrial sales growth expectations once again: ETR's objective is to reduce the risk profile and paint the story as a more regulated firm.

Figure 129: Entergy Analyst Day 2016 Guidance

Analyst Day 2016 Guidance	2015A	2016E	2017E	2018E	2019E	2020E
Utility, Parent, & Other EPS Mdpt.	3.43	4.35	4.70	4.90	5.10	5.40
Annual Growth	-9%	27%	8%	4%	4%	6%
2016E-2020E CAGR		5.6%				
Ratebase (\$Bn)	17.5	19.5	21.0	23.0	24.5	25.8
Annual Growth		11%	8%	10%	7%	5%
2016E-2020E CAGR		7.2%				

Source: Company Filings

- **Generation growth, just not to the same degree as previously:** We start by highlighting distribution opportunities but Entergy still has large generation projects on the horizon. ELL and ETI (Louisiana and Texas) selected the self-build options in the respective jurisdictions RFPs which are each for up to 1,000MW. For cost reference the 980MW St. Charles CCGT is expected to cost ~\$870Mn. Management intends to file details by 3Q16 in each state with an approximate twelve month approval process needed.

ETR is working on <5MW of solar pilot programs across its jurisdictions but it is unclear whether they will participate.

Renewables? Not explicitly identified as an opportunity. Entergy has renewable RFPs in Louisiana (200MW), Arkansas (100MW), and New Orleans (20MW) and has not specified whether it will participant in the process which should be initiated in May/July. Entergy has historically submitted self-build options in prior RFPs for fossil plants but has less experience developing renewables compared with conventional generation. While a modest piece of the capex budget, participation in these processes was not identified in the capex outlook.

- **Smart meters and more grid modernization:** The focus of the 2014 Analyst Day was the “unique sales growth opportunity” from local economic development potential and while ETR’s industrial sales growth have been above-average, it has generally fallen-short of the original plan. For this reason management presented a renewed focus on distribution, particularly smart meters as Entergy has not yet deployed the technology across its service territory. We emphasize the passage of bonus depreciation tips the balance in favor of capital vs. ongoing labor expense of meter readers all the more. The national emphasis on smart meters is a prime example of utilities continuing to deliver ratebase growth without associated meaningful bill inflation given the overall cost synergies. For example Entergy expects only a ~2% monthly residential bill impact through the end of the decade which is aided by the roll-off of a securitization as well.

ETR has limited smart meter penetration across its service territories today,

Shortly after the Analyst Day in the third quarter management is expected to begin making the necessary regulatory applications for smart meter investments (AMI) which will be the bedrock for further investment.

Addressing SPP and MISO ‘seams’ is a unique opportunity for ETR.

- **Transmission also picking up steam:** Transmission spending is anticipated to pick-up to \$800-\$900Mn in 2019/2020 from \$600-\$700Mn in 2015/2016 due to “asset management” spending where ETR proactively looks to replace equipment with better technology. Entergy is uniquely positioned to aid in addressing the seams issue between SPP and MISO to improve the integration, potentially reducing the reliability requirement over time. This “economic” transmission is a small sliver of the annual spending (less than \$50Mn per year) but we believe this could also grow over time.
- **How important is load growth to the guidance?:** As mentioned 20% of the 2016-2020E generation capital investment is designed to meet increasing load growth which equates to ~\$1.3Bn (\$250Mn annually). Included in the plan is 1.5-2.0% consolidated sales growth which is supported by management's 2.75-3.5% expected industrial growth target. Generation growth represents \$1.3Bn out of the \$16Bn capex plan and in a scenario where sales growth is ‘only’ 100bp this would trim ~20bp off the CAGR. Furthermore additional distribution upgrades could be removed from the base plan if growth does not materialize as planned.

- **Customer bill inflation:** With the lower sales growth, mgmt is targeting to keep the average customer's bill to 2% inflation. We flag \$1.8 Bn in upcoming storm securitization offsets to regular investments as a key tailwind to enable continued investment; management specifically highlighted 2018 in Louisiana as a key year for bill headroom.
- **Earned ROE – targeting 2018:** Mgmt emphasized it was targeting to earn its ROEs at roughly its authorized levels across all of its jurisdictions by ~2018 (partial year in 2017), prior to accounting for the impact of its nuclear reinvestment program. We interpret mgmt's substantial focus on the subject at the Analyst Day and caution on recovery as indicative of clear risk with respect to state-level recovery of capex necessary to improve its nuclear portfolio (specifically Pilgrim and ANO) back to Column 4.

- **What are upside areas in the capex plan?**

- **1. Gas ratebasing: Entergy did not quantify the potential size of the investment but plans to make files before year-end in both Louisiana and Mississippi.** Investors continue to question the companies' ability to execute on this spending area following notable setbacks in Colorado and Florida. ETR discussed that the Louisiana and Mississippi Public Service Commissions have the authority to approve gas reserve investment but convincing stakeholders and executing on a plan with a positive near-term customer benefit could be challenging. Timeline points to back half of the plan as a framework would first be necessary prior to implementation of a wider effort.
- **2. Return for incremental nuclear safety capital spending:** Among the key messages was the recovery of nuclear capex and opex (likely measured in the \$100s of millions) from regulators as it aims to improve operations across its nuclear portfolio, with a specific focus on its Arkansas Nuclear One (ANO) asset. The overall focus at the Analyst Day on the issues tied to nuclear surprised many investors, and the update could drive more lasting caution through much of the year.

Regulatory recovery of Nuclear capex and opex is key:

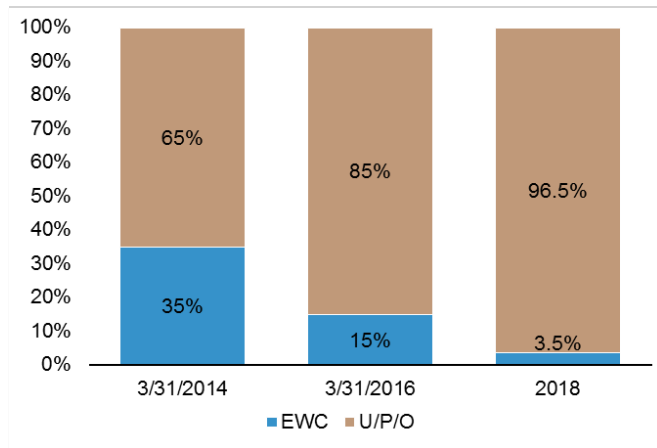
While we had anticipated the latest Analyst Day to prove the key annual update, providing a full view of capex, the focus now shifts to the EEI update around both the updated scale of the program as well as expectations for recovery. Admittedly without a clear pathway to regulatory recovery

Timeline for program update makes EEI quite important

- **3. Further smart grid spending:** Most of this appears outside of the 2016-2020E timeframe but management estimates this could be a \$6-\$8Bn opportunity "through 2025 and beyond" compared with \$700Mn in the current five-year plan. In tandem with its focus on advanced ratemaking, mgmt. revealed for among the first times opportunities tied to Smart Meters as part of its growing focus on distribution-level opportunities to drive incremental EPS growth.
- **Advanced Ratemaking? Long-Term prospects:** ETR alluded to the potential for advanced ratemaking mechanisms for the first time, discussing to the desire to pursue new regulatory paths, seemingly not to improve its earned ROE prospects, but rather to afford a greater avenue to other earnings opportunities (ex. incentives). While providing few specifics today, this would appear to allude to similar efforts among progressive states such as New York and

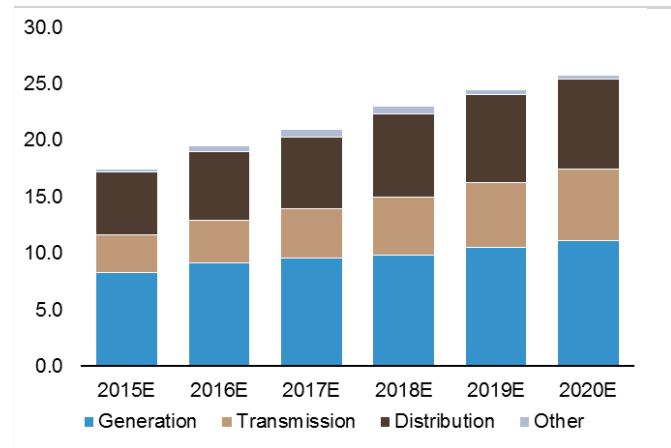
California in rethinking the compact. It remains unclear at present what the overall opportunity will be. Mgmt's informal guidance provides for negligible earnings by ~2020 under its forecast period, suggesting our prior estimates were too high for the EWC business (we are modestly lowering these).

Figure 130: Actual and Projected EPS Mix



Source: Company Filings

Figure 131: Ratebase Projections by Year (\$Bn)



Source: Company Filings

Entergy Wholesale Commodities (EWC):

▪ Nuclear costs could decline in the long-term despite near-term pick-up:

Entergy's recently hired Chief Nuclear Officer discussed at length his plans for the entire nuclear fleet (not just EWC) to improve "performance deficiencies" and overall streamline operations. This could eventually reduce long-term costs for the regulated and unregulated nuclear plants but management warned this could drive additional near-term spending. For example the extended Indian Point Unit 2 outage is expected to last ~100 days from early March through mid-June vs late-June previously but compared with a ~27-day refueling outage in 2014) and drive a ~\$0.20 loss in 2016 plus higher costs spread across the refueling cycle (~\$0.05 in 2017). Following the Unit 2 inspection management has decided to accelerate the inspection for Unit 3 but it is not expected to take as long as the unexpected Unit 2 inspection because the equipment has been reserved. ETR stated that it is working to reduce nuclear overhead to avoid an increasing cost allocation as the scale of its EWC business has declined citing examples such as outage management.

Specifically looking at the NRC Column 4 units at Arkansas Nuclear One (ANO), the NRC presented its 2015 safety assessment report on April 6th and we look for more details from the supplemental information in the near-term. The results of the report will give an indication on how much of \$50Mn Column 4 costs will persist beyond 2015. Entergy is hopeful that it can exit Column 4 in late 2017-mid 2018 indicating that there is still a relatively long runway of higher expenses ahead. The NRC inspections for Pilgrim are expected in 2H16 but are less of an investor focus given management's plans to close the plant on May 31, 2019 and the scope is more limited than at ANO.

- **Piece of spend will be tied to EWC as well:** We emphasize a further undetermined piece of the Nuclear sustainability capex will be tied to its unregulated EWC business, adding to cumulative cash flow pressures through the current period. Recall Entergy opted earlier to keep Pilgrim open despite its Column 4 operations rather than buying out its capacity obligation in the ISO-

Entergy is the only nuclear owner in the US to have units in the NRC's Column 4 classification (Arkansas Nuclear One and Pilgrim).

At the previous Analyst Day management guided to the low-end of the ~0.5-2.5% non-fuel O&M/refueling outage expense CAGR 2013Adj-2016E range.

NE incremental auctions for the two-year refueling cycle. We note the plants location in the constrained SEMA market makes it more challenging to replace the capacity at palatable price (if possible at all) give the substantial additional capacity required.

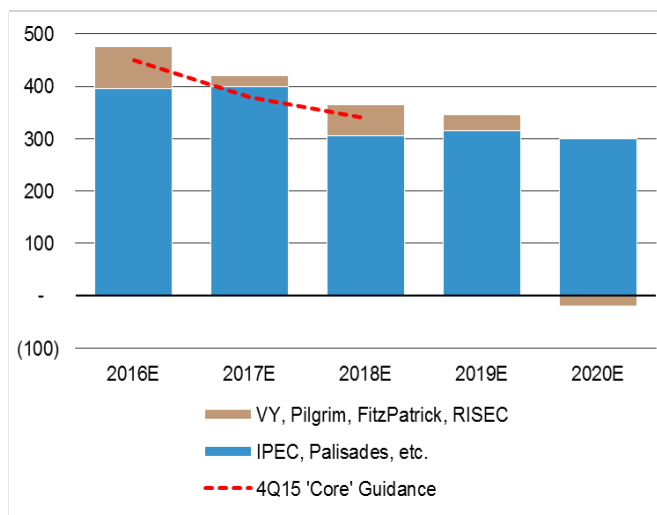
- **An 'orderly exit in New York'?** The question remains amidst the decision to sell Fitzpatrick rather than sell it how ETR will handle itself over Indian Point. We note the ZEC impact on the market overall will have a negative power and potentially even capacity price impact downstate. While Fitzpatrick was ETR's principal negotiating leverage to establishing a deal over Indian Point, we believe the decision to keep this other plant open at least improves the relationship with the Governor.
 - Further, amidst the risk of increasing costs, we see clear potential for negative EPS from the EWC business, only further pushing ETR to accelerate retirements (this negative EPS trigger has historically proven the decisive factor in evaluating whether to hold onto merchant power for other diversified utilities).
- **Palisades – Management continues to leave left the door open to a better NPV proposition:** We believe management is open to evaluating all options with respect to the contracted Palisades nuclear plant in Michigan based on its comments that it would like to become a fully regulated company. We see the difficulties in reaching a deal to shut-down the plant in an accelerated buy-out of the obligations as principally due to local considerations around the impact to the community and associated property tax revenue. The LCOE of building a new CCGT plant for CMS likely approaches ~\$5¢/KWh, not too dissimilar from its existing PPA with the nuclear facility (\$5-6¢/KWh through the remainder of its life). Alternatively, we could envision a deal in which CMS pays ETR to buy-out of the above-market contract obligation and in turn replaces the asset with its own merchant plant DIG, via a re-ratebasing effort. This would reduce the portion of unregulated earnings for both entities.
- **Less hedging at Indian Point going forward:** With EWC expected to represent nearly 0% of EPS in 2020E management is more comfortable utilizing a lower than historical level of hedging for Indian Point in order to capture any upside in merchant economics versus what ETR perceives as relatively limited downside.
- **Parent guarantees not necessary but that risk remains in the future if facts change:** Following nuclear peer Exelon's disclosures that it could have to supply parent guarantees for its retiring Clinton and Quad Cities nuclear plants in Illinois, investors have been focused on whether that is a possibility for Entergy. Entergy's plants are fully funded with over \$100Mn excess at all plants except Indian Point 2 (\$47Mn excess) and Palisades (\$77Mn excess). Although we believe the risk that management will have to provide decommissioning financial support in the future is low today, we believe that this risk should be reflected in the valuation to some degree.
- **Ongoing costs for EWC:** Entergy has guided to \$7-\$10Mn EBITDA drag for its plants annually after the units shutdown (-\$20Mn in 2020E for Vermont Yankee, FitzPatrick, and Palisades) indicating that if Entergy closes all of its nuclear units it could incur a -\$35Mn to -\$50Mn annual FCF drag.

With retirement planned in six months , we see limited latitude for the decision to be reversed at this point.

With its next refueling outage slated for Spring 2017, timing would appear ideal in the next several months.

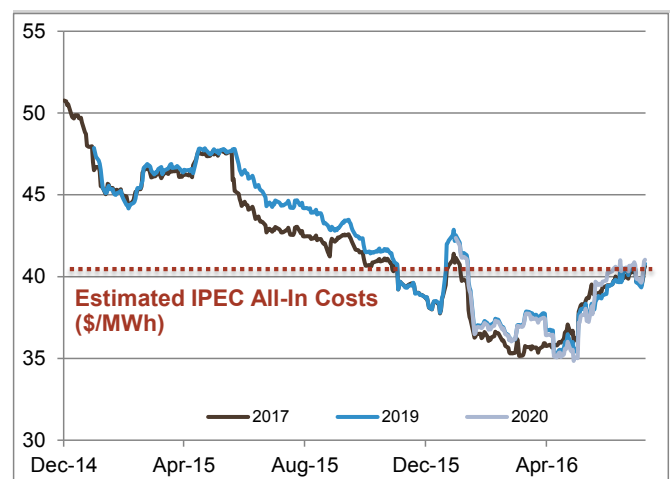
We see the ball as firmly with CMS on next steps

Figure 132: EWC Adjusted EBITDA Guidance (\$Mn)



Source: Company Filings

Figure 133: NY Zone G ATC Power (\$/MWh)



Source: Platts

Parent & Other:

- **Dividend growth to continue but limited with payout ratio already above the range:** *Given the higher dividend payout and focus on reaccelerating capital spending we forecast 3-4% annual dividend growth between 2015-2020E. By growing the dividend at the bottom-end of this range (half of UP&O EPS growth) management can reduce the payout ratio to 72% (within stated 65-75% target range). In contrast, if management is comfortable at the very top-end of its range then we believe a solid 4% CAGR is a possibility.*
- **Pension Impact:** Turning to 2017 expectations, pension would appear a headwind yet again which management quantified at \$0.14/sh based on the 50bp delta between the current interest rate and the discount rate embedded in the plan. \$0.09-0.10 attributable to the utilities. We see pension as a consistent variability in results; and indicative of a wider forthcoming headwind for the sector.
- **Taxes poised to drive 2016 above top end of range:** Management reiterated that multiple tax items, split between the utilities and EWC could well drive FY2016 results above the top end of its EPS range; this is despite headwinds already identified driving it towards the bottom half of the range. Tax items could come as soon as 2Q results (at least in part).
- **How are the agencies thinking of the leverage? Some latitude:** We emphasize both Moodys and S&P appear poised to continue to re-rate the utilities as business risk associated with the merchant nuclear businesses continues to decline. We see the risk profile as eventually evolving to the similar "Excellent" category consistent with fully regulated utility peers, with a corresponding FFO/debt metric requirement of 16-18% (SO, DUK, etc. per our understanding of Moodys definitions). We emphasize FFO metrics continue to exclude the impact of nuclear maintenance capex (CFO adjusted for working capital), limiting the direct comparability to peers. The 21% FFO / Debt is at the high-end of the currently targeted range (13-23%) and there could be latitude from the credit rating agencies if their assessment of the risk profile improves. The continued ownership of generation – and specifically nuclear generation –

Entergy remains above its nominal Debt/EBITDA targets at 4.6x Debt/EBITDA (vs. the target range of 3.5-4.5x) but expects the metric to improve into the range within twelve months.

will likely limit any further material improvement. The ~4.6x debt / EBITDA is expected to improve when a full year of Union EBITDA is included but the point remains that Entergy is already quite levered.

- **What about the Holdco:** Consistent with peers, we see ETR as poised to continue to add incremental leverage (despite being among the more levered already) in an effort to bolster its organic EPS growth rate. While we admire management's decision to lever via organic investment rather than via more pricey acquisitive angles, we emphasize the approach adds to its substantial leverage. We note mgmt. is likely to continue to trend towards the higher end of its parent debt –to-total debt target of 18-20% in the near-term.

Further details are available in our report '[Pivoting from Generation to Distribution](#)'.

For more detail ETR, please see our other recent reports:

[6/13/16: Ratebase Profile Still Married to Load Growth](#)

[4/27/16: Pivoting From Generation to Distribution](#)

[2/22/2016: Industrial 'Evolution'](#)

[2/18/2016: Trimming Sales Expectations Again](#)

[11/3/2015: Two Things are Certain in Life: Retirement & Taxes](#)

[10/9/2015: Kickstarting the Exit Process](#)

Valuation: Maintain Sell rating, Increasing PT to \$75 (+5/sh)

We value Entergy at \$75/sh, up from \$70/sh previously. This is comprised of \$77/sh for the regulated utilities, parent, & other and -\$2/sh for the unregulated business which generates FCF and has the potential for more significant liabilities as we have seen at nuclear peer Exelon. While we do not anticipate additional nuclear liabilities at this point given the positive funding status, this is a risk that we believe should be incorporated into shares.

On a comparable UP&O guidance basis we effectively value the utility at a ~10% discount (7% with parent preferred allocation adjustments) and an all-in discount of ~12% when factoring in the merchant business.

In contrast the market implied P/E discount is 1-2%, too low in our view due to the risks at the utility and FCF drag at the unregulated subsidiary.

Our UP&O estimates remain unchanged. Management continues to forecast 2016 operating UP&O with weather at the bottom-end of the guidance range but stated that it could have favorable tax items which pull results back into the top-end or above the range.

Figure 134: Entergy EPS Estimates

EPS by Segment	2014A	2015A	2016E	2017E	2018E	2019E	2020E
Regulated Utility	4.64	6.12	5.58	5.93	6.11	6.42	6.71
EWC/Nuclear	2.19	1.03	0.65	0.97	0.30	0.48	0.32
Other	(1.00)	(1.15)	(1.37)	(1.34)	(1.27)	(1.33)	(1.39)
Consolidated	5.83	6.00	4.86	5.56	5.15	5.58	5.64
Prior UBSe	5.83	6.00	4.86	5.54	5.07	5.32	5.38
Consensus (6/9/16)		5.83	5.12	5.24	5.19	5.25	5.50
Guidance (1Q16)		5.50-6.10	4.95-5.75				
Adj. Utility Parent & Other UBSe (Inc. Weather)		3.35	4.20-4.50	4.50-4.90	4.70-5.10	4.90-5.30	5.20-5.60
		4.97	4.21	4.59	4.85	5.09	5.32
Regulated Payout %		67%	81%	77%	75%	74%	73%
UBS % Change			0%	0%	2%	5%	5%
EPS CAGR Guidance		5-7%					UBSe Weather-Adjusted 5.2%
EPS CAGR (2016E-2020E)		5.6%					UBSe Unadjusted 6.0%

Source: Company Filings and UBS Estimates

Figure 135: Entergy Valuation – Raising to \$75/sh from \$70

Entergy Corp. Sum-of-the-Parts Valuation								
	2018 EPS	P/E Multiple				Equity Value per Share		
		Low	Prem/Discount	Base	High	Low	Base	High
Regulated Utilities		2018 Peers	17.7x					
System Energy Resources, Inc. (SERI)	0.79	16.7x	0.0x	17.7x	18.7x	13.13	13.92	14.70
Entergy New Orleans	0.20	15.7x	-1.0x	16.7x	17.7x	3.17	3.37	3.57
Entergy Mississippi	0.88	15.7x	-1.0x	16.7x	17.7x	13.77	14.64	15.52
Entergy Louisiana	1.64	15.7x	-1.0x	16.7x	17.7x	25.76	27.40	29.05
Entergy Gulf States (Louisiana Only)	1.05	15.7x	-1.0x	16.7x	17.7x	16.54	17.60	18.65
Entergy Texas	0.61	15.7x	-1.0x	16.7x	17.7x	9.51	10.12	10.72
Entergy Arkansas	1.09	15.7x	-1.0x	16.7x	17.7x	17.05	18.14	19.23
Other	(0.14)	16.7x	0.0x	17.7x	18.7x	(2.28)	(2.42)	(2.56)
Regulated Utility (Consolidated)	6.11					96.65	102.76	108.88
Interest Expense	(0.38)	18.7x	0.0x	17.7x	16.7x	(7.06)	(6.69)	(6.31)
Parent Preferred Income	(0.71)	18.7x	0.0x	17.7x	16.7x	(13.25)	(12.55)	(11.84)
Other Parent Exp (non-Pfd)	(0.37)	18.7x	0.0x	17.7x	16.7x	(6.87)	(6.50)	(6.14)
Total Utility Equity Value per Share	4.66	16.4x		16.5x	19.5x	\$76.52	\$77.03	\$90.91
Merchant Generation Equity (Drag): NPV of FCF						(2,083)	(527)	-
Net Cash (YE 15)						-	220	220
Mn Shares Outstanding (2018E)						179	179	179
Merchant Generation Equity Value per Share						(\$10.40)	(\$1.71)	\$1.23
Total Equity Value per Share						\$66.00	\$75.00	\$92.00

Source: Company Filings, FactSet, and UBS Estimates

Eversource Energy

We remain on the sidelines upon our latest review of shares, seeing too much uncertainty around the upcoming Supreme Judicial Court (SJC) decision for Access Northeast. Following the latest delay to the Northern Pass project, we see risk around negative EPS revisions heading into 2Q.

We forecast 2Q16 adjusted EPS of **\$0.63** vs \$0.65 in 2Q15 and \$0.66 Consensus.

- **Key Drivers:** Higher transmission earnings are a positive for the quarter but we believe this could be offset by the impact of the negative comparison with the PURA accumulated deferred income taxes in the quarter.
- **Wildcard Factors:** (1) Ability to control costs to offset with 2-3% annual reduction in guidance but the comparison in 2Q15 will be challenging because last year was unusually low; (2) magnitude of regulatory lag [depreciation, property taxes]

Figure 136: ES 2Q16E Earnings Walk

Eversource Energy 2Q16 Earnings Walk	EPS
2Q15A Adjusted EPS	\$0.65
Weather vs Normal in 2Q15	\$0.01
Weather vs Normal in 2Q16	\$0.00
Electric Transmission: \$485Mn ↑ Ratebase	\$0.02
Electric Distribution & Generation	
Sales Growth: 0.0%-0.5%	\$0.01
PURA ADIT Settlement	(\$0.02)
Natural Gas Distribution	
NSTAR Gas Case: +\$15.8Mn	\$0.00
Customer Growth: +800 customers YoY	\$0.00
Utilities Cost Structure	
Non-Tracked O&M: 2-3% Reduction	(\$0.01)
Property Taxes, Depreciation, & Other	(\$0.02)
Parent & Other	(\$0.02)
Dilution	\$0.00
2Q16E Adjusted EPS	\$0.63
2Q16 Consensus	\$0.66
2016 UBSe EPS	\$2.98
2016 Consensus	\$2.98
2016 Guidance	\$2.90-\$3.05

Source: Company data, UBS estimates, company filings

O&M typically represents a net saving for YoY for Eversource but there was an unusually low level of spending in 2Q15 which causes a YoY drag for the quarter.

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

- [7/12/16 Passing on Gas?](#)
- [7/8/16 Ticking Towards High Noon in New England](#)
- [5/11/16 Just Passing Through, with Added Urgency](#)
- [3/30/16 Dousing the New England Grid](#)
- [3/23/16 Benefiting from Anomalous Conditions, for Now](#)
- [2/5/16 Adding to New England Import Prospects](#)
- [1/15/16 How Green Can New England Get?](#)
- [12/31/15 Picking a Price for the New England Auction](#)
- [12/14/15 Going Eye to Eye with the Public on NPT](#)
- [11/5/15 Enhancing the Grid](#)
- [8/18/15 Tunnelling Through to an Approval](#)
- [8/3/15 Pipe & Wire Plans Moving Right Along](#)
- [7/22/15 A Thumbs Up for Northern Pass](#)

What are the key updates for ES?

- **Will Northern Pass and Access Northeast projects be approved and contribute to growth?:** We think successfully executing on the two projects appears more ambiguous of late. While Northern Pass actually appears to be gaining traction from a contracting perspective, we see risk around citing considerations before the Site Evaluation Committee in New Hampshire following a near year-long delay in that process with the final review now expected in 2H17 at the earliest, which would potentially facilitate construction beginning later in 2017. While we actually have some degree of confidence arising from our recent conversations that a pathway towards a compromise on route and terms can be found for Northern Pass. Citing considerations are also relevant as the project is in front of the NH Supreme Court with regards to routing on public access highways.

For the proposed ~900mcf/d Access Northeast gas pipeline, contracts in MA and RI are under regulatory review, with CT poised to release an RFP and NH will review contracts this year as well. ES and partners Spectra Energy and National Grid plan to submit a full FERC filing later this year as demand firms up, with the goal of having major sections online by the winter of 2018/19. We continue to see a need to accomplish at least one of these projects to achieve the low end of management's 5%-7% earnings CAGR target through 2019, while achieving both would allow the company to reach the high end.

- Earlier this week, ES was successful in getting contingent approval from Maine on procurement from Access Northeast, pending approval from other New England states. Coordination remains key.
- **Survey shows clear discrepancy between industry and investor expectations:** We recently polled investors and industry participants on expectations for success of ES' two core projects heading into a critical period for both. We note investors polled largely continue to expect success for each at 68% and 79%, respectively for Access Northeast and Northern Pass, respectively, albeit on a smaller sample size. This is notably different from industry expectations which pinned the odds at 34% and 54% for each project, respectively. We read the more sober expectations on gas contracting from industry relative to investors, in addition to our own doubts, as a further cautious datapoint. Further details are available here: [7/12/16 Passing on Gas?](#)
- **How meaningful is Mass energy legislation remains the offsetting potential?:** While the focal point will be the meaningful renewable procurement authorized (and in turn likelihood of contracting for these resources via long-term contracts on transmission for hydro), we see potential for other avenues to be broached (two bills passed need to be reconciled by July 31) with a positive read-through to ES on further nascent off-shore wind for instance. Further, should Access Northeast fail, we see a particularly acute pressure to provide greater grid resilience from electric imports during peak winter months to alleviate gas shortage concerns. Ultimately, given existing shortages already experienced and inability to connect new gas customers, we believe energy imports remain an inevitability (with other projects aside these two a possibility).

We emphasize shares could see some pressure in the near-term from a negative SJC decision given the ~\$0.20/sh estimated project contribution once fully in-service in 2019.

We are rapidly shifting our concerns from a focus on whether the project will be contracted (we see the Mass legislation as potentially poised to contract for the entire project). Rather, we see the ongoing NH SEC process as well as key efforts before the NH Supreme Court over citing along public access routes as ever more critical. The region appears willing to contract for it, but can it get done?

We emphasize ES' long-term prospects arising out of not just the latest legislation in MA, but the wider backdrop of ambitious energy policy in the region remains quite real.

- **Prospects for Balance Sheet Deployment? Look for Fall update:** With a late 2016 review contemplated around capital allocation decisions, we expect a busy 2H for ES management as they evaluate a range of potential investment opportunities to offset the projected excess cash balance in 2017 resulting from the forced divestment of ratebase generation in NH. We would interpret a decision to repurchase shares at current levels as among the least attractive opportunities, seeing this as a cautious datapoint.

[Share buybacks: just how much coming? This remains a central question in expectations.](#)

The New Hampshire Public Utility Commission recently approved the settlement between Eversource and state regulators regarding the asset sale of Eversource's remaining rate base assets. Eversource will be allowed to recover from ratepayers the \$415.5 million invested into the scrubber at the Merrimack plant from ratepayers or via a third-party transaction. Focus will be on mgmt to execute and find new projects to potentially backfill and replace any lost projects, including not just nascent community solar projects, but project efforts to address regional offshore or renewable desires.

- **Rate Cases Coming Up:** Raising Risks into 2017: We see the next round of cases as offsetting the potential improvements into next year, given cases in several of its key utilities in MA and CT. While we do not see immediate risks tied to these cases, this increases the prospective risk profile and interest rate sensitivity. We believe the core stories will continue to revolve around execution the two key projects.

Figure 137: Upcoming Rate Cases

Jurisdiction	Company	Commentary
Massachusetts	NSTAR Electric	Base rates frozen through 12/31/2015
	WMECO	Base rate cases filed in 2017
	NSTAR Gas	\$15.8 million base rate increase effective 1/1/2016
Connecticut	CL&P	Next case: 2nd half of 2017, effective 12/1/2017
	Yankee Gas	Need to file by 2019
New Hampshire	PSNH	Next distribution rate request will no occur before 7/1/2017

Source: Company Filings

Estimates Unchanged

We include a 50% probability for each Northern Pass and Access Northeast.

Overall, our latest estimates point to the lower end of the 5-7% EPS range, with mgmt now talking up buybacks, we're a bit cautious. We continue to see a need to accomplish at least one of these projects to achieve the low end of management's 5%-7% earnings CAGR target through 2019, while achieving both would allow the company to reach the high end.

Figure 138: ES Estimates vs Consensus, 2014A-2019E

Annual EPS	2014A	2015A	2016E	2017E	2018E	2019E
Transmission	0.93	0.96	1.04	1.12	1.22	1.26
Distribution, Generation	1.48	1.60	1.65	1.64	1.65	1.72
Yankee + NSTAR Gas	0.23	0.23	0.29	0.30	0.30	0.31
Northern Pass @ 0% probability	0.01	0.01	0.01	0.02	0.05	0.10
Access Northeast @ 0% probability	0.00	0.00	0.01	0.03	0.07	0.10
Corp & Other	0.00	0.01	(0.03)	(0.03)	(0.03)	(0.03)
UBSe	\$2.65	\$2.81	\$2.98	\$3.08	\$3.26	\$3.48
CL&P Dist ROE	8.6%	8.0%	6.8%	7.8%	8.6%	9.5%
PSNH Dist ROE	9.3%	8.7%	8.7%	9.7%	6.1%	6.4%
Prior			\$2.99	\$3.17	\$3.40	\$3.60
Consensus			\$2.99	\$3.19	\$3.38	
Guidance			\$2.90-\$3.05			
5%-7% EPS growth from 2016 \$2.90-\$3.05 to 2019			UBSe 2016-19 CAGR		5.3%	

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

Valuation: Maintaining \$61 Price Target

The Northern Pass and Access Northeast projects are valued by discounting their earnings in 2020e and 2019e, respectively, to the valuation year and applying the average peer 2018E P/E (with a 1.5x premium for transmission and a 1.0x premium for gas transportation). We attribute a modest \$2/sh today for both.

Figure 139: ES Sum of the Parts Valuation on 2018E P/E

Sum of the Parts 2018E	Valuation	Low Case		Base Case		High Case	
		Valuation (\$s MM)	Multiple	Valuation (\$s MM)	Multiple	Valuation (\$s MM)	Multiple
Business Segment	Metric	2018E	Multiple	Value	Multiple	Value	Multiple
Regulated Business							
					Peer Multiple	18.0x	
					Premium :		
PSNH, WMECO, NSTAR Distribution	P/E	\$1.08	17.5x	\$6,028	0.5x	18.5x	\$6,717
CL&P Distribution	P/E	\$0.57	17.0x	\$3,057	0.0x	18.0x	\$3,417
Transmission	P/E	\$1.22	17.5x	\$6,790	1.5x	19.5x	\$7,955
Yankee & NSTAR Gas	P/E	\$0.30	18.0x	\$1,739	1.0x	19.0x	\$1,932
Parent	P/E	(\$0.03)	17.0x	(\$149)	0.0x	18.0x	(\$166)
					Probabilities		
Northern Pass 2020 EPS, Discounted 2-Yr	P/E at 50% prob	\$0.09	18.5x	\$0	50%	19.5x	\$275
Access Northeast Pipeline 2019 EPS, Discounted 1-Yr	P/E at 50% prob	\$0.10	18.0x	\$0	50%	19.0x	\$296
NU Equity Value				\$17,466		\$19,425	\$21,055
Fully Diluted Outstanding Shares (2018E)				318		318	318
NU Equity Value per Share				\$55.00		\$61.00	\$66.00

Source: Company Filings, UBS Estimates, FactSet

Exelon Corp.

The key at the August Analyst Day will be inspiring confidence in the regulated outlook (7-9% EPS CAGR expected to be rolled-forward rather than increased) while explaining why management believes its unregulated retail marketing business deserves a premium valuation – we remain skeptical on this latter.

We forecast 2Q16 adjusted EPS of **\$0.58** vs \$0.59 in 2Q15 and \$0.54 Consensus.

Exelon will not be hosting a 2Q16 earnings call.

- **Key Drivers:** We expect BGE to decline modestly due to regulatory write-offs which management intends to include in ongoing operations. If not for this unexpected negative, management would have surpassed its 2Q16 EPS guidance range of \$0.50-\$0.60.
- **Wildcard Factors:** (1) Realized energy margin and counterbalancing retail portfolio performance; (2) O&M reduction efforts at the utilities and ExGen; and (3) taxes and other overhead at ExGen

Figure 140: EXC 2Q16E Earnings Walk

EPS	Exelon Corp 2Q16 Earnings Walk
\$0.59	2Q15A Adjusted EPS
(0.06)	Baltimore Gas and Electric (BGE)
(0.05)	Margin: ~\$200Mn Rate Request [\$300Mn ratebase increase]
(0.01)	O&M, D&A, and Other: Cost Cuts offsetting inflation
0.02	PECO Energy (PECO)
0.02	Margin: Rate Increase (\$127Mn January 2016) [\$500Mn ratebase]
0.00	O&M, D&A, and Other: Cost Cuts offsetting inflation
0.01	Commonwealth Edison (ComEd)
0.03	Ratebase Growth: \$1.3Bn Increase Pre-Bonus Depreciation
(0.01)	30-year Treasury Trend: 50bp = \$0.02/sh FY
(0.01)	O&M, D&A, and Other: \$0.01 Bonus D&A drag
(0.03)	Exelon Generation (ExGen)
(0.02)	Gross Margins: Normalization of cost to serve and MtM
0.02	O&M: Lower Costs net of Inflation
0.01	O&M: Refueling/Unplanned Outages
(0.02)	D&A and Other
0.00	Effective Tax Rate: Expected to be similar to 2015
(0.01)	Other: Interest, Decommissioning, etc.
0.05	PEPCO Holdings (POM)
0.11	Contribution from Pepco
(0.02)	Interest Expense: \$4.2Bn @ 3.8% on June 11, 2015
(0.04)	Dilution: 57.5Mn shares @ \$32.48 on July 14, 2015
\$0.58	2Q16A Adjusted EPS
\$0.50-\$0.60	2Q16 Guidance
\$0.54	2Q16 Consensus
\$2.57	2016 UBS _e EPS
\$2.54	2016 Consensus
\$2.40-\$2.70	2016 Guidance

Source: Company filings, FactSet, UBS estimates

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

- [7/13/16 Setting the Tone on Nuclear](#)
- [5/9/16: The Clock is Ticking](#)
- [5/6/16 Nuclear Showdown](#)
- [3/23/16 Third Time is the Charm \[POM Decision\]](#)
- [3/4/16 Illinois – Losing The Nuclear Advantage.](#)
- [2/5/16 Capital Allocation In Transition](#)
- [1/13/16 We Just Can't Get There](#)

[11/2/15 Taking a Bite Out of Pepco Accretion](#)
[10/20/15 Exploring EDF's Nuclear Put on Exelon](#)
[9/28/15 A Concentrated Nuclear Play](#)
[9/10/15 Keeping the Nuclear Option Alive](#)
[8/31/15 Can Exelon Turn The Tide in DC?](#)
[7/31/15 Catalysts Galore](#)

What's the Focus at the Analyst Day

We note management will not be hosting a call; rather the Analyst Day on August 10th will serve as the 2Q earnings recap as well.

- **Utility EPS.** We look for management to extend its current 2016-2018 EPS growth CAGR out to 2019 or 2020, likely continuing the 7-9% trajectory. We see a longer 5-year window as sending a message of conviction in being able to achieve persistent above average growth both through opportunities to do so (ROE, etc) as well as confidence in long-dated ExGen cash flows to fund the reinvestment cycle.
- **Contracted generation.** Beyond just a focus on a Utility EPS growth story, mgmt appears quite clear in delivering a message focused around *contracted* generation growth. As such, this would lend itself more towards a renewable biz than a merchant generator; the question is whether this side of the business will be expanded given tensions on PTCs with nuclear.
- **What are prospects post-POM for ROE improvement?** We emphasize the POM stand-alone story going into the acquisition was nearing on distressed given customer satisfaction and poor reliability metrics. The question is whether EXC will prove able to use the payments provided to customers an reinvestment back into its system as effectively the key to re-engaging its relationship with regulators to enable an improved ROE across each of the service territories.
- **Retail Valuation: Should it be a differentiated multiple from GenCo?** We look for management to reiterate not just its superior position in energy retailing, but the case for a business valued at a full GenCo multiple. In the current instance, we note there is no difference as we value the entirety of the GenCo and retail business at a discounted 6x multiple to account for the reduced FCF from its nuclear portfolio. We stress the vast majority of the FCF from the consolidated entities is tied to the retail businesses.
 - **Breaking down retail: Wholesale vs Mass Market:** We emphasize the EXC business is principally large-scale competitive customers and a wide range of other parties. This is contrast to the more single purpose retail businesses of NRG and TXU Energy in Texas, where each makes the bulk of their EBITDA and FCF from their legacy retail businesses.
- **The Nuclear Reality.** We look for management to articulate its efforts to achieve success on nuclear contracting *beyond* New York State. While its latest success on ZECs bodes quite well to EPS (see our note [Setting the Tone on Nuclear](#)). We emphasize prospects

How Much Value does this add?

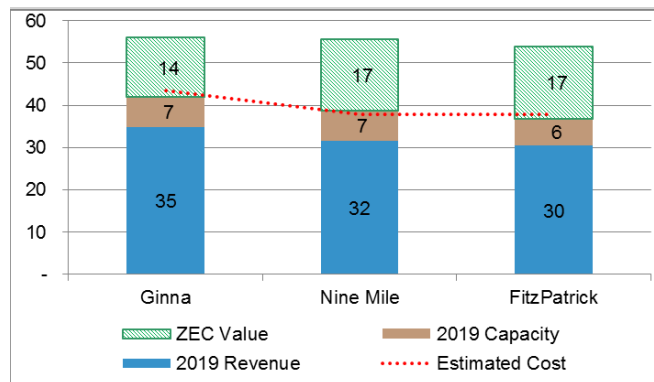
Below we show the summary of potential value creation for the three plants on an NPV basis using a 13% discount rate. We estimate ~\$1/sh for Fitzpatrick in acquisition NPV as well as ~\$1/sh in uplift for the two plants (Ginna and Nine Mile).

Figure 141: NY Nuclear Summary for ZECs

NY Nuclear Summary for ZECs				
Asset	Avg FCF	Total FCF	NPV	Per Sh
FitzPatrick	\$111	\$1,553	\$509	\$0.57
Ginna	\$44	\$613	\$246	\$0.28
Nine Mile	\$146	\$2,040	\$835	\$0.94
Total	\$300	\$4,205	\$1,590	\$1.79

Source: Company Filings, Platts, SNL Energy, and UBS Estimates * Per Sh represents EXC shares and assumes a \$100Mn purchase price for FitzPatrick.

Figure 142: NY Nuclear Summary for ZECs (2019E \$/MWh)



Source: Company Filings, Platts, SNL Energy, and UBS Estimates

Similarly we show the potential value uplift by using a 6x EV / EBITDA multiple which is largely consistent with the high discount rate approach above.

Figure 143: EBITDA and EPS Value Added by ZECs

Company	EBITDA Associated with ZECs (\$M)	EBITDA Increase Associated with ZECs (in %)	Value EBITDA Associated with ZECs 6x Multiple (\$M)	Value EBITDA Associated with ZECs 6x Multiple (\$/share)	EPS Associated with ZECs (\$/share)	EPS Increase Associated with ZECs (in %)
Exelon	\$ 164.2	2.07%	\$ 985.4	\$ 1.06	\$ 0.12	4.02%
Entergy	\$ 121.9	3.08%	\$ 731.3	\$ 4.09	\$ 0.44	8.74%

Source: Company Filings, Platts, SNL Energy, and UBS Estimates

Re-estimate the CENG Put Value Option

We see ZEC resolution as driving a decision point on the Put, which we *now* expect to be executed. Under this agreement, EXC would be required to buy EDF out of its 50% JV stake in CENG. This could equate to *as much as* ~\$850 Mn, net of the \$600 Mn in debt from quite modest values prior (we had estimated ~\$50 Mn as of October 2015). [See our prior CENG EDF Put note here.](#)

Figure 144: Pinning a New Value on the JV (@ 13%)

Latest DCF on Calvert Cliffs @ 20-Years	\$371
Added ZEC-Based DCF Value (~Equal to Asset Value):	
Ginna	\$246
Nine Mile	\$835
CENG 5.25% \$400 Mn Loan	-\$400
CENG 8.5% remaining \$400 Mn Pfd	-\$199
Total Potential Price Point	\$853

Source: Company reports and UBS estimates

What is the outlook for Pepco?

Exelon has a busy regulatory calendar for 2016 with rate cases planned in Washington D.C., Delaware, and Maryland, which follows the New Jersey and Maryland cases. Although Exelon did not provide an update on capex or earnings expectations for Pepco, EXC disclosed that it anticipates +\$700-\$850Mn cash flow from the combination of bonus depreciation and use of NOLs. 2015 earned ROEs ranged from 4.8%-7.4%, all well below the allowed ROEs of 9-10%, indicating that there is room for improvement if EXC can control costs and receive constructive rate case outcomes. In the NJ and MD cases Exelon has requested 10.6% ROEs. A headwind to earnings growth will be contracting sales growth with Atlantic City Electric (ACE) forecasted to fall by -2.2% in 2016E given the backdrop of 7.3% unemployment. The only utility with real load growth expected is PECO at +0.40%.

We highlight the Maryland Potomac Electric rate case where the PSC Staff recommended a 9.57% ROE and the Office of People's Counsel suggested a 8.65% ROE.

Ex-POM, Exelon reaffirmed its 2016-2018 7-9% net income growth expectations

On average Pepco historically filed ratecases every ~22 months across the jurisdictions with an average of eight months per case

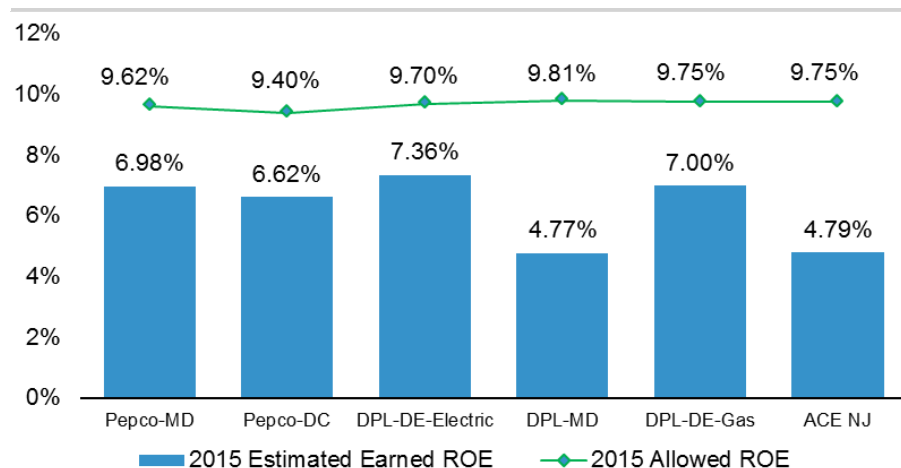
Figure 145: Pepco Pending Rate Cases

State	Company	Docket	Service	Filing Date	Increase (\$Mn)	Change (%)	ROE (%)
District of Columbia	Potomac Electric Power Co.	FC-1139	Electric	6/30/2016	85.5	20.30	10.60
Delaware	Delmarva Power & Light Co.	D-16-0649	Electric	5/17/2016	62.8	10.60	10.60
Delaware	Delmarva Power & Light Co.	D-16-0650	Natural Gas	5/17/2016	21.5	13.20	10.60
Maryland	Delmarva Power & Light Co.	C-9424	Electric	7/20/2016	66.2	12.81	10.60
Maryland	Potomac Electric Power Co.	C-9418	Electric	4/19/2016	126.6	20.49	10.60
New Jersey	Atlantic City Electric Co.	D-ER-16030252	Electric	3/22/2016	84.4	24.60	10.60

Source: SNL Energy

Exelon has previously guided to a -\$0.05 drag in 2016, which improves to +\$0.20 accretion by 2020 seemingly based on an 8% earned ROE. Although the company did not explicitly update its POM guidance, it stated that its forecast was *at least* in-line with the previous EEI disclosures.

Figure 146: 2015A Earned vs. Allowed ROE at Pepco Utilities



Source: Company filings

Updated EPS estimates

Given the sharp compression in EV/EBITDA values for IPPs, we continue to see relative P/E multiples as less informative for EXC. While it appears quite cheap vs. peers on historic P/E metrics, most investors continue to frame the story in the context of a total SOP value.

Figure 147: Updated Exelon EPS Estimates; does not include POM

Exelon Consolidated EPS	2015	2016	2017	2018	2019
PECO	0.43	0.45	0.47	0.51	0.55
ComEd	0.48	0.55	0.57	0.63	0.70
BGE	0.31	0.31	0.34	0.37	0.39
Exelon Generation	1.40	1.31	1.36	1.46	1.20
Other	(0.13)	(0.06)	(0.07)	(0.06)	(0.05)
Total EPS	2.49	2.57	2.67	2.90	2.80
Guidance	\$2.60	\$2.70			
Consensus	2.49	2.54	2.64	2.79	2.81
Prior UBS estimates	2.49	2.57	2.64	2.84	2.71
Accretion from POM Deal	(0.13)	(0.05)	-	0.07-0.12	0.15-0.20
Regulated EPS (UBSe)	\$1.22	\$1.32	\$1.38	\$1.51	\$1.64
Regulated Guidance Midpoint	\$1.24	\$1.34	\$1.42	\$1.50	N/A
	7-9% off 2016 base with POM				
Dividend Per Share	\$1.24	\$1.26	\$1.29	\$1.32	\$1.35
Utility Payout Ratio (Ex-POM)	102%	95%	93%	88%	82%
Utility Payout Ratio (W./-POM)	114%	99%	93%	82%	74%

Source: Company filings, FactSet, UBS estimates

Updated EXC Valuation: Raising Target to \$38/sh (+\$3)

We are revising up our price target to reflect:

- The DCF of the potential ZEC uplift in New York for Both Ginna and Nine Mile. Depending on the final terms of Fitzpatrick, we believe this could be upwards of another \$1/sh in uplift depending on sale price (we had thought \$100 Mn).
- We also revise up our regulated utility values to reflect group utility multiple
- Among the more valid emerging points of debt on the valuation is whether the regulated utility will continue to garner a discounted valuation given its above average EPS growth profile of 7-9%? We hold constant our multiples for the legacy EXC Utilities (BGE, ComEd, and PECO)
 - In turn we are ascribing a 1x P/E *premium* (from -1.0x previously) to the POM utilities given the potential for ROE expansion as mgmt executes. We note datapoints remain constructive from all accounts
- We do not include any EDF Put Option execution. Presumably while likely to occur at this point, this would be done at a fair market value leaving our SOP unchanged.

Figure 148: Exelon Sum-of-the-Parts

All figures in US \$ million except per share data				EV/EBITDA & P/E Multiple			Enterprise Value						
	2018 EBITDA	Low	Base	High	Low	Base	High						
Generation	1,974	4.0x	6.0x	7.0x	7,897	11,845	13,820						
DOE Nuclear Fuel Disposal Fee Uplift	150	3.0x	4.0x	5.0x	450	600	750						
Hedge Value	(305)	5.0x	6.0x	7.0x	(1,524)	(1,829)	(2,134)						
Other/Equity Investments	214	4.0x	6.0x	7.0x	856	1,284	1,498						
Retail & Wholesale Margin (Power+Non-Pow)	797	4.0x	5.0x	6.0x	3,188	3,985	4,782						
Total / Implied	2,830	3.8x	5.6x	6.6x	10,867	15,886	18,716						
Total EBITDA w/Hedges	3,135												
add DCF Value of ZEC Deal (Ginna + Nine Mile Only)					856								
less ExGen Net Debt					(7,522)								
less HoldCo debt					(1,300)								
add Hedge Value					305								
Equity Value					2,350	8,224	10,199						
Mn. Shares Outstanding (2018E ex-POM)					889	889	889						
Merchant Generation Value Per Share					\$ 2.64	\$ 9.25	\$ 11.48						
Regulated Utilities				P/E Multiple			Equity Value						
	2018 Net Income	EPS	Low	Peer	Prem/ Discount	Base	High	Low	Base	High			
BGE Net Income	324	\$0.37	15.8x	17.8x	-1.0x	16.8x	17.8x	5,115	5,439	5,762			
PECO Net Income	450	\$0.51	17.8x	17.8x	1.0x	18.8x	19.8x	8,012	8,462	8,912			
ComEd Net Income	559	\$0.63	16.3x	17.8x	-0.5x	17.3x	18.3x	9,120	9,679	10,238			
Total / Implied	1,333	\$1.51	16.7x			17.7x	18.7x	22,246	23,580	24,913			
Mn. Shares Outstanding (2018E ex-POM)								889	889	889			
Regulated Utility Value per Share								\$ 25.03	\$ 26.53	\$ 28.03			
POM EPS Accretion (2018 UBSe)					\$0.10	17.8x	17.8x	1.0x	18.8x	19.8x	\$ 1.78	\$ 1.88	\$ 1.98
Total Equity Value per Share								\$ 29.00	\$ 38.00	\$ 41.00			

Source: Company Filings, FactSet, and UBS Estimates

FirstEnergy Corp.

We believe that new Distribution Modernization Rider structure (or some form, potentially better) will ultimately be approved, we believe shares setup well into a ~Fall approval of the construct. We see the PUCO as undeterred by recent rejections of similar structures and keen to provide support to its local utilities through a vehicle that does not face similar oversight risk from FERC. More broadly, we are constructive on shares into a potential balance sheet fix update.

We forecast 2Q16 adjusted EPS of **\$0.53** vs \$0.53 in 2Q15 and \$0.54 Consensus.

- **Key Drivers:** Similar to 1Q16, we expect the regulated distribution utilities' earnings to decline YoY while the competitive segment improves due to premium ATSI capacity pricing (\$357/MW-day compared with \$126/MW-day). The magnitude of the FES uplift is expected to be much lower due to only a partial period of higher capacity revenue. Performance at the regulated utilities also has the headwind of less incremental rate relief YoY. Also note that regulated transmission is expected to decline YoY due to a 2Q15 true-up
- **Wildcard Factors:** (1) Performance at FES; (2) Cost cutting efforts at FES and the regulated businesses; (3) Sales activity which has been a headwind in recent quarters.

Figure 149: FE 2Q16E Earnings Walk

FirstEnergy 2Q16 Earnings Walk	EPS
2Q15A Adjusted EPS	\$0.53
Regulated Distribution:	
Weather vs Normal in 2Q15 Degree Days +30%	(0.06)
Weather vs Normal in 2Q16 Degree Days +11%	0.02
Distribution Sales Growth: Slightly Negative	(0.02)
OH: DCR Rider June 1st +\$30Mn YoY	0.00
WV: \$13Mn Pre-Tax Earnings Impact; Effective ~Mar. 2015	-
PA: \$205Mn Pre-Tax Earnings Impact; Effective May 2015	0.03
PA: LTIP Investment: \$56Mn expected to be deployed in '16	0.00
JCP&L: +~\$20Mn Net Rev Increase; Effective April 2015	-
O&M: Approximately flat due to CF plan and NJ reversal	0.00
Pension & OPEB (MtM excluded from ongoing)	(0.02)
Depreciation & Amortization and Property Taxes	(0.01)
Investment Income and Financing Costs	(0.00)
Regulated Transmission:	
Revenues net of D&A and taxes: Higher ratebase	0.03
Financing, Taxes, and Other	(0.05)
First Energy Solutions (FES):	
Commodity Margin: Higher capacity and lower cost to serve	0.12
Depreciation, O&M, Pension, and Other	(0.01)
Reduced Investment Income	(0.01)
Parent & Other:	
Parent Drag: 36.0% in 2015 vs ~37.5% Normal Tax Rate	(0.01)
Dilution	(0.00)
2Q16E Adjusted EPS	\$0.53
2Q16 Consensus	\$0.54
2Q16 Guidance	N/A
2016 UBSe EPS	\$2.50
2016 Consensus	\$2.68
2016 Potential Guidance Range (\$2.50 Midpoint)	\$2.35-\$2.65

Source: Company Filings, FactSet, and UBS Estimates

We look for a flat quarter as higher ATSI capacity pricing offsets broader headwinds for the company.

We do not expect management to provide either 3Q16 or FY16 guidance as management has stated there is too much uncertainty given the Ohio ESP proceedings.

Additional details on the FY16 segment drivers are available in our 3Q15 FE note, [In a Holding Pattern Above Columbus](#).

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

[7/19/16 Reaching the Pivot Point](#)

[7/12/16 How Much Debt Can the Utilities Support?](#)

[7/08/16 Ohio: When There's a Will, There's a Way...](#)

[5/31/16 What to Make of the Recovery](#)

[5/31/16 Deal Time Approaches](#)

[5/06/16 Contracting: What is the Street Expecting?](#)

[5/02/16 Successfully Going Back to the Drawing Board](#)

[4/28/16 The First Shoe Drops](#)

[4/01/16 Scoring a Contract](#)

[3/28/16 Getting MOPRized](#)

[2/17/16 Pension Woes](#)

[12/2/15 At the Goal Line in Columbus](#)

[11/2/15 In a Holding Pattern Above Columbus](#)

[10/13/15 Will Ohio Come Through?](#)

[8/3/15 Keeping Up With The Jones](#)

What are the key updates for FE?

- **What do we think of shares?** We remain Neutral rated on the shares. On the positive side, near-term expectations remain quite low, with most investors expecting on average \$1.5 Bn in equity issuance per our latest survey by 2018 as well as most (60-70%) don't expect success in Ohio on any further revenues. Further with talk of outright re-regulation legislation growing (albeit we don't believe it's quite possible), we see the outlook for this year as relatively positive.

However, this is offset by the longer-term, which we see as still relatively constrained as challenges tied to the core generation business remain front and center. We don't expect balance sheet issues to be resolved simply with a near-term equity check (even as large as \$2Bn) as there is the risk of further need for equity to stabilize the business in subsequent years (really in 2019+) as capacity prices fall. We emphasize the latest capacity auction outcome back to \$100/MW-day without ATSI breaking out had a particularly negative impact on the prospects for FES. Moreover, with continued generation likely to pressure dark and spark spreads in Ohio, we wouldn't doubt energy margin pressures to follow capacity in the state. Finally, we don't see much confidence for a meaningful improvement YoY (2020/2021) under a full 100% implementation of Capacity Performance (CP) either (or at least relative to Street expectations for +\$70/MW-day off the recent \$100 print).

- **What are the Options for FirstEnergy?** We see a 'solution' as gradually emerging from the fold, driven by three key elements:
 - (5) **Ohio distribution compensation:** A solution focused on avoiding the pitfalls of generation-tied contracts appears to be emerging. This could cover at least \$130 Mn, if not upwards of \$200 Mn.
 - (6) **Further cost costs?** Following the latest (weak) capacity auction results, we would not be surprised to see yet another wave of cost cuts at plants. The question remains whether this includes outright retirements, or just marginal reductions. We perceive a fundamental tension tied to

the need to reinvest back in assets to ensure adequate CP compliance. The bulk of the portfolio appears to have cleared the latest auction, clearing on a tiered basis (across all assets rather than just selecting certain higher cost assets from clearing). We emphasize this would likely be from FES, with more limited savings from the core utilities as the companies look to re-scale investment; as such we exclude this impact below from our focus on the core Regulated + Parent EPS

- (7) **An equity raise?** We see upwards of \$2 Bn as a potential raise. We calculate the \$131 Mn (post-tax) would exactly offset the potential impact of a ~\$2 Bn capital raise. The investment would likely be focused on 'growth' investments to kickstart the ratebase engine (and could be spread over a multi-year period of time, say 2018).

Figure 150: FE Credit Metrics for Merchant (FES & AES) and Regulated (FE Standalone)

CFO pre-W/C					
	FE Consolidated	FES	AES	FE Standalone	
2011	\$2,766	\$890	\$345		\$1,531
2012	\$2,293	\$566	\$279		\$1,448
2013	\$2,792	\$837	\$203		\$1,752
2014	\$2,636	\$564	\$147		\$1,925
2015	\$3,293	\$785	\$232		\$2,276
2016	\$3,462	\$931	\$196		\$2,335
Debt					
	FE Consolidated	FES	AES	FE Standalone	
2011	\$21,556	\$5,253	\$1,783		\$14,520
2012	\$22,972	\$5,865	\$1,314		\$15,793
2013	\$24,381	\$4,576	\$645		\$19,160
2014	\$26,722	\$4,493	\$678		\$21,551
2015	\$27,135	\$4,290	\$653		\$22,192
2016	\$27,427	\$4,321	\$645		\$22,461
Adjusted Moody's CFO pre-W/C / Debt					
	FE Consolidated	FES	AES	FE Standalone	
2011	12.8%	16.9%	19.4%		10.5%
2012	10.0%	9.7%	21.2%		9.2%
2013	11.5%	18.3%	31.5%		9.1%
2014	9.9%	12.6%	21.7%		8.9%
2015	12.1%	18.3%	35.5%		10.3%
2016	12.6%	21.5%	30.4%		10.4%
2011-2015 Avg.	11.3%	15.1%	25.9%		9.6%
FFO / Debt Benefit from Reducing Debt by \$1Bn			0.48%		
FFO / Debt Benefit from Increasing FFO by \$100Mn			0.36%		

Source: Moody's, Company Filings, and UBS Estimates

Although the FES credit metrics appear solid today (20% minimum FFO / Debt for investment grade at the competitive segment), we forecast adjusted EBITDA declining from \$1Bn at the midpoint of 2016E guidance to below \$500Mn by 2018 as capacity revenues decline and energy hedges roll-off. For example FE guides to \$815Mn of capacity revenue in 2016 but only \$465Mn in 2019.

Why the focus really should be on S&P – and risks of a downgrade

Among further questions raised of late by many in examining FirstEnergy is simply letting the parent company drop to a HY rating for the purposes of Moodys ratings. However, what is critical in the FE structure is the linked nature of the HoldCo to the OpCo's for the S&P methodology. While the

Concern is on how S&P links Holdco rating to Opcos

agency permits a lower FFO/Debt than Moodys at 12%, the critical issue would appear the risk of having the ratings of the Opco's dropped. We believe regulators are loathe to see the FE family of regulated utilities en masse dropped to HY (despite the likely limited incremental cost of debt in the current market). As such, we see this as the principal reason why letting the rating fall approach for the HoldCo is not a palatable outcome.

- **Bigger question: how could the FE compensation structure be challenged?** The real question remains how any new deal could be rejected by prior opponents of the structure. While doubts most likely will remain, we have more confidence in the latest structure. Though we sense a reticence to provide meaningful revenue support to companies via full re-regulation, discussion remains active in the state. Prospects for such an eventuality would appear a further positive backdrop for FE into the Fall. Any discussion would really be a 2017 legislative discussion, if at all.
- **Road to improving earnings challenging outside of Ohio as well:** While most of the attention is on the Ohio proceedings, FE filed rate cases in New Jersey and Pennsylvania in late April where management guided to +\$0.60 EPS up lift from the cases (+\$0.40 in PA and +\$0.20 in NJ) but as discussed in our [1Q16 note, much of the request is to compensate for lost sales as load declines](#). Additionally, we anticipate significant pushback on the ROE above-average ROE requests. In PA testimony is expected in late July while the New Jersey process could be more protracted.
- **Pension MtM weighs on FE particularly hard and further complicates leverage story:** As of 12/31/15 FE's pension was only 61% funded versus a historical average of 75-80% for utilities. US treasury rates have declined 80-100bp since that point which will create even more earnings and funding pressure for management. Management disclosed in its 10K that it could meet the upcoming pension obligation with a combination of equity and cash; however, management previously indicated that it has no plans to meet the pension funding deficit with FE shares.

Re-regulation: a real dialogue emerging back in the state but this would likely be a 2017 event if at all.

In 3Q15 FE disclosed plans to invest \$25Mn of O&M in 4Q15 which is designed to show management's commitment to improving operations in New Jersey

Figure 151: FE Pension Analysis

FE Pension Analysis (\$Mn)			
	2016	2015	Delta
Liability	(8,704)	(8,889)	185
Assets	5,338	5,822	(484)
Net Liability	(3,366)	(3,067)	(299)
2016 Min Funding	381	324	57
2017 Min Funding	N/A	555	N/A
Expected Return %	7.50%	7.75%	-0.25%
Discount Rate %	4.50%	4.25%	0.25%
*\$160Mn of the \$381Mn 2016 obligation contributed as of Feb			
Increase in Net Periodic Benefit Cost Sensitivities			
-25bp Discount Rate		292	
25bp Return		14	

Source: Company Filings

Figure 152: 30Yr US-Treasury Yield



Source: FactSet

Valuation: Maintain at \$35

We continue to use a sum-of-the-parts methodology with P/E multiples for the regulated utilities and non-interest parent drag. We continue to net out the parent debt given the magnitude, utilization of revolver which understates interest expense, and overall risk profile for the generation (assuming FES is non-recourse). Our valuation does not include any contribution from the Distribution Modernization Rider/PPA construct. We utilize 17.7X multiple, in line with recent utility sector peer multiple expansion.

Figure 153: FE Sum-of-the-Parts Valuation

Regulated Utilities	2018 Net Income	P/E Multiple				Equity Value			
		Low	Peers	Premium/ Discount	Base	High	Low	Base	High
<u>Core Utilities</u>									
Energy Delivery (FE and AYE Utilities)	914	16.2x	17.7x	-0.5x	17.2x	18.2x	\$14,801	\$15,715	\$16,628
Add'l Utility Capex NI @ \$ 1Bn Spend	50					18.2x			\$910
Transmission (ATSI, TRAIL)	362	17.7x	17.7x	1.0x	18.7x	19.7x	\$6,410	\$6,772	\$7,134
<i>Total EPS</i>	2.98								
<u>Parent Costs</u>									
Net HoldCo/Parent Expenses (SG&A, etc)	(228)	16.7x	17.7x	0.0x	17.7x	18.7x	(\$3,803)	(\$4,031)	(\$4,259)
Add Back: Parent Interest Expense	128	16.7x	17.7x	0.0x	17.7x	18.7x	\$2,145	\$2,274	\$2,402
<i>Net Parent EPS (SG&A ex-Interest)</i>	(0.23)								
Total / Implied Utilities	1,227	15.9x			16.9x	18.6x	\$19,553	\$20,730	\$22,816
<i>Total Regulated EPS</i>	2.87								
Number of Shares Outstanding - 2018 (Mn)							428	428	428
Regulated Utilities & Transmission Equity value per share							\$45.74	\$48.49	\$53.37
Less: Recourse FES Obligations							(\$2,000)	(\$1,100)	(\$1,100)
Less: Other Parent Sale Leasebacks							(\$388)	(\$388)	(\$388)
Less: Parent Notes (12/31)							(\$4,200)	(\$4,200)	(\$4,200)
Plus: FES Cash Distributions to Parent (NPV 2017-2020), ~approx							(\$1,100)	\$0	\$1,219
Parent/FES Drag per Share							(\$17.98)	(\$13.31)	(\$10.45)
FirstEnergy Combined (Regulated & FES) Equity Value							\$28.00	\$35.00	\$43.00

Source: Company filings, FactSet, UBS estimates

ITC Holdings Corp.

Fortis has secured a minority investor for Fortis and is progressing with the regulatory approval process. The FERC review process is expected to be more critical than the state processes where the attention will be on intervenor filings.

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

[7/11/16 Can Transmission ROEs Go Up?](#)

[7/1/16 Tide Going Out for Transmission ROEs Still](#)

[4/29/16 Transmitting the Latest Policy Signals](#)

[4/13/16 Electing to Get a Bonus?](#)

[2/23/16 Searching For Clues in Regulated M&A](#)

[2/10/16 Fortisified](#)

[12/1/15 Exploring an Exit](#)

[9/30/15 Perfect Storm](#)

[12/19/14 The SMID Bid: The Context for Regulated M&A](#)

What are the key updates for ITC?

- **Fortis agreed to sell the top-end of the percentage range (19.9%) for ITC but ~\$100Mn below the top-end of the valuation range:** On April 20th Fortis announced that it had agreed with GIC Private Limited (GIC; a sovereign wealth fund in Singapore with \$100+Bn AUM) to purchase 19.9% in ITC Holdings (ITC) for \$1,228Mn as part of the Fortis-ITC acquisition announced in February. At the announcement of the transaction Fortis guided to selling 15-19.9% of ITC at a valuation of \$1.0-\$1.4Bn USD. With Fortis trading at \$30.74 USD the minority interest transaction represents a ~13% discount to where shares were trading in late April when announced and a ~19% discount to mid-July pricing.

Can ITC keep the independence adder? While it is unclear how the FERC will decide on this topic, if neither Fortis nor GIC operate within the same regional transmission footprint as ITC, an argument could be made that ITC should be able to keep the 50bp independence ROE incentive.

- **Regulatory approval process expected to begin in June at the latest:** All five states and the FERC filing have been made and management still expects the transaction to close by year-end. The FERC has 180 days to review the transaction indicating a possible decision by early December. Fortis expects to receive state approval from Illinois, Kansas, Missouri, Oklahoma, and Wisconsin by the Fall where ITC has commented that the approval process is progressing well. Both ITC and Fortis shareholders have approved of the transaction.
- **Decision on Erie expected in upcoming months:** A final decision whether ITC will proceed with its Lake Erie transmission project is expected to be made in 2H16. When deciding whether it will invest in the project ITC has stated that the transmission line would need to be significantly contracted with risk commensurate with the reward.

Following the minority interest investment Fortis shares declined 3.5% to close the week but is approximately in-line with the broader utilities index (XLU).

Fortis agreed to sell the top-end of the percentage range (19.9%) but ~\$100Mn below the top-end of the valuation range.

State regulatory approvals are required in IL, KS, MO, OK and WI (not in IA, MI or MN). Only FERC has any direct rate authority over ITC

Mgmt has stated that the Lake Erie project development is going well but there is no update available yet.

- **We see a positive evolution possible in peer group establishing FERC ROEs:** We performed our latest mark-to-market analysis of transmission ROEs in early July to understand where ROEs could trend in future periods on the back of the latest MISO Proposed Decision (PD). See our [initial write up](#) and case developments [here](#). We emphasize that while the ALJ's PD pointed 9.7% ROE for the six-month period through November, we see a more recent period ending through June 2016 would find an ROE of 9.4% without Avangrid, but a more likely, constructive outcome of 10.5% with Avangrid (full peer group tables below). We see the relevant peer group and the inclusion and exclusion of several key companies as critically swinging this analysis, primarily Avangrid (AGR) which was formed on 12/16/15 when the merger of UIL and Iberdrola USA was completed.

Valuation: Increase Price Target \$2 to \$48

Our valuation is based on the acquisition offer from Fortis which is a combination of cash (\$22.57) and Fortis shares. The \$2/sh increase in our Price Target is driven by the appreciation of Fortis shares which lifts the stock component of the transaction.

Figure 154: ITC Valuation

Base Case: Takeout Price Update Calculation	
FTS-TSE Price (C\$)	Cd\$43.30
FTS-TSE Price (USD)	USd\$33.47 (A)
ITC Price	USd\$46.52
Cash Consideration	\$22.57 (C)
FTS Stock	0.7520 (B)
Current ITC Valuation	\$48 (A)*(B)+(C)
Current ITC Market Cap	USd\$7,113
Minority Interest (19.9%)	\$1,228
Implied Value per Share	\$39.87
Discount	-16%

Source: Company Filings, FactSet, and UBS Estimates

NextEra Energy

Following the termination of the Hawaiian Electric transaction the focus turns to the Oncor process in Texas where management has explicitly indicated interest if the price is right. After the detailed update of NEER with 1Q16, investor attention turns to the significant rate case where we believe the risk of ROE erosion has increased following the latest step-down in US treasury rates.

We forecast 2Q16 adjusted EPS of **\$1.67** vs \$1.56 in 2Q15 and \$1.52 Consensus.

- **Key Drivers:** The reversal of strong weather in 2Q16 for the utility and below-average wind at NextEra Energy Resources (NEER) is expected to be a net negative but largely offset. We continue to expect the utility Florida Power & Light (FPL) to continue earning its ROE through the use of depreciation credits available for use through the balance of 2016.
- **Wildcard Factors:** (1) Wind output with Avangrid [AGR] pointing towards a wind being 10% below normal in 1H16; (2) customer supply & trading, and other at NEER

Consensus expects another decline YoY for NEE but the drivers point to an improvement versus 2Q15. We ultimately expect another solid beat like NEE delivered last quarter.

Figure 155: NEE 2Q16E Earnings Walk

NextEra Energy 2Q16 Earnings Walk	EPS
2Q15A Adjusted EPS	\$1.56
FPL: Targeting Earning 10.5-11.5% ROE	
Weather vs Normal in 2Q15	(0.09)
Weather vs Normal in 2Q16	0.03
Sales & Usage Impact: -0.5% to Flat	(0.01)
New Investments	0.07
Wholesale	0.01
Incentive Mechanism	0.00
Depreciation Reserve Amortization	0.02
Energy Resources	
Customer Supply & Trading	0.04
New Investment	0.08
Existing Assets	
Return to Normal Wind (93% in 2Q15)	0.06
Impact of Wind in the Quarter	(0.02)
Refueling Outages and Other Impacts	0.00
Gas Infrastructure	0.02
Asset Sales	0.00
Corporate G&A and Other	(0.07)
Dilution	(0.04)
2Q16E Adjusted EPS	\$1.67
2Q16 Consensus	\$1.52
2016 UBSe EPS	\$6.32
2016 Consensus	\$6.19
2016 Guidance	\$5.85-\$6.35

Source: Company filings, FactSet, UBS estimates

We believe the discussion around 2Q will likely principally focus on M&A implications/ balance sheet considerations as mgmt may not be in a position yet to discuss implications from latest IRS guidance on repowering & refurbishment.

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

[5/31/16 Can Repowering Put Wind in NEE's Sails?](#)

[5/5/16 Sunny Days Ahead](#)

[4/15/16 How about a Nice Hawaiian Punch](#)

[3/29/16 More Questions Surface Over Oncor](#)

[3/22/16 Is Oncor Slipping Away?](#)

[2/11/16 Growing Renewables With or Without CPP \(Mgmt Meetings\)](#)

[2/1/16 Beating Guidance Once Again](#)

[11/30/15 EFH Lassoed Texas Gas Plants](#)

[11/23/15 Still Kicking the Tires in Texas](#)

[10/29/15 Reinvesting in the NEE Family](#)

[9/17/15 Still The Industry Leader](#)

[8/30/15 Ramping up Expectations](#)

What are the pivotal questions for NEE?

- **After Hawaiian Electric – what is next?:** On Friday July 15th the Hawaii Public Utilities Commission (PUC) voted 2-0 that the pending NextEra Energy-Hawaiian Electric (NEE/HE) merger was not in the public interest. Commissioners Iwase and Akiba voted against the deal while Gorak abstained. While the Commission offered specific guidance on how to refile, NEE ultimately opted not to continue the deal. With the deal not closing, NEE owes \$90Mn (taxable) to HE as a break-up fee plus fee reimbursement. Details of the order are available here: [Summary](#) and [Full Order](#). HE mgmt has previously stated the NEE payment would forgo equity needs for this year.
- **Commission has left the door open to alternative filings:** The commissioner provided guidance on any revised deal terms to make the deal palatable in a lengthy follow up to the order. These areas include: ratepayer benefits, mitigation of risks, achievement of the State's Clean Energy Goals, Competition, Corporate Governance, and the HECO transformation. HE has stated that it is not currently evaluating any other proposals.
- **Oncor process getting increasingly crowded, likely reducing NEE's chances:** The latest [media reports](#) regarding the Energy Future Holdings bankruptcy process around its Texas T&D Oncor Electric Delivery subsidiary indicates that Berkshire Hathaway is one of the "leading bidders" with offers coming in the \$18-\$19Bn range. Other parties mentioned include Edison International, Hunt Consolidated, NextEra Energy, and a consortium of current creditors. While NextEra Energy had been a front runner as the 'stalking horse' bidder, we believe that as the bidding process expands, NEE's probability of winning clearly declines with mgmt downplaying the deal under this context. Media has suggested this could be a July development, making this a potential near-term announcement. Lastly, we emphasize creditors and minority owners appear to be launching their own final efforts to keep the utility.

Hawaii PUC rejects NextEra Energy-Hawaiian Electric Merger 2-0

Further Notes on Oncor:

[3/22/16 Is Oncor Slipping Away?](#)

[3/29/16 More Questions Surface over Oncor](#)

[4/29/16 Opening Up Oncor: The Hunt is On](#)

[5/24/16 What is the Oncor Accretion?](#)

[7/5/16 The Latest on What Oncor Means](#)

- **Why is NEE pursuing a deal? We think it's tied to tax capacity.** While the improvement in its relative risk profile per the credit rating agencies would appear the clear logic behind its contemplated bid of Oncor and previous interest in Hawaiian, we believe another purpose behind the latest wave of utility acquisition interest is likely tied to projected tax capacity as it continues to scale its renewable effort, particularly solar with an upfront ITC recognized. Mgmt has in recent days emphasized it does not 'need' a transaction for any rating agency purposes, but would appear to optimize the continued ramp in both tax credits and non-regulated EPS.
- **Still receptive to acquisitions but price has to be right:** At our utilities conference, management commented that it is challenging to extract meaningful accretion from regulated acquisitions when paying a significant premium but it continues to be open to the idea if the right opportunity presents itself. Echoing comments from the March 2015 Analyst Day, the company believes it has a very transferable skill set on utility operations (cost control, generation planning, etc.) that it could bring to other utilities. The company's preference in M&A would be to pursue utilities that are not earning at their allowed ROEs and/or have opportunities to extract costs to create headroom for capital spending opportunities. If NEE were to pursue a transaction it would not want lose its BBB senior unsecured S&P credit rating.

Management is interested in regulated acquisitions to keep an appropriate balance between its regulated utility operations and its unregulated business as well amidst the disproportionate growth in the contracted wind business.

- **We see a modest opportunity with repowering principally in California, but also Texas eventually:** We estimate NEE's ~20-30% market share in potentially repowered US wind installations positions the company well to take advantage of recent wind repowering IRS guidance, but the actual potential may be limited by the specifics of site age, capacity factor step-up and contracting regime. Up to ~2.4GW of Texas wind built pre 2011 could be under review, but ~345MW of California assets likely provide the most interesting opportunity if capacity factors can be substantially improved from old technology, which could yield ~\$53-66M of NPV benefit to NEE versus continued operation of legacy assets. NEE's first focus will be on contracts rolling off and those post-PTC life. We estimate a typical 20 year old California asset could yield ~12% IRR in a repowering scenario, while 10 year old wind in Texas is likely in the mid-to-high single digits. Overall, we see repowering adding ~\$1-2/sh of total value.
- **Competition for wind development has been declining:** NEER has observed a decrease in competition but has not seen any real increase in % margins. Many of its main competitors from five years ago are no longer in the business although there have been some names that continue to appear (ex. Invenergy). For example. Solar competition continues to be healthy with lower barriers to entry but we believe NEE has advantages over smaller developers.
- **While management may not elaborate on the call, we still expect developments as NEE looks to recycle capital by divesting uncontracted assets and/or adding project debt to unencumbered assets:**

Factors that management considers:

- Ability to reduce O&M
- Opportunity to deploy more capital with the headroom created from less O&M
- Under-earning
- Maintain or strengthen the balance sheet

We do not expect management to be in a position yet to discuss implications from latest IRS guidance on repowering & refurbishment.

- **Set to further reduce merchant volatility with potential Marcus Hook deal:** According to media reports NextEra is in advanced negotiations to divest its 794MW Marcus Hook co-generation asset in PA. In 2006 the Long Island Power Authority agreed to a 685MW capacity contract with the Marcus Hook plant effective 2010; we estimate ~\$90Mn of annual EBITDA for the plant. Management has stated that it is open to divesting merchant assets to raise capital to support continued investment in contracted renewables as well as reduce overall commodity sensitivity. Other unregulated conventional assets include, Sayreville Cogeneration (160MW net ownership in NJ), and Bellingham Cogeneration (168MW in MA). The Cogeneration assets have PPAs with the local utilities.

We believe its merchant wind portfolio in West Texas could be one of the next assets targeted.

The last review of the New England portfolio did *not* result in a sale but management has indicated that further non-core asset sales are possible to reduce equity needs.

- **Adding leverage to unencumbered assets is a further source of funds:** Management has 6-12 projects on the balance sheet that do not have leverage as of YE15 and depending on the characteristics of the assets management would be comfortable adding 70% leverage (project finance) to the contracted assets which would help reduce capital needs. Assuming ~70% financing against a ~\$1,200/kW value (depending on the depreciated life), suggests \$500-800Mn by our estimates.

Wind assets in other markets running off contract could be eligible for sale; these are likely quite small outside of Texas.

- **Focus turns to FPL ratecase – hoping for status quo:** NEE subsidiary Florida Power & Light (FPL) formally in mid-March a \$1.3Bn four-year request (January 2017 - December 2020) with the Florida PSC for new base rates that would be implemented in 2017 with an 11.5% ROE midpoint (including 50bp premium for historical “exemplary performance”). We believe that simply maintaining the ability to earn the same ROE will be perceived positively by the market. FPL’s current ROE is established at 10.5%, with an allowed ROE band of +/- 100bp and the Company has historically earned at the top-end of the range, principally predicated on use of legacy depreciation credits. Docket 160021-EI

If NEE is able to just keep its ROE we believe that would be received quite favorably by investors but there is increased risk given

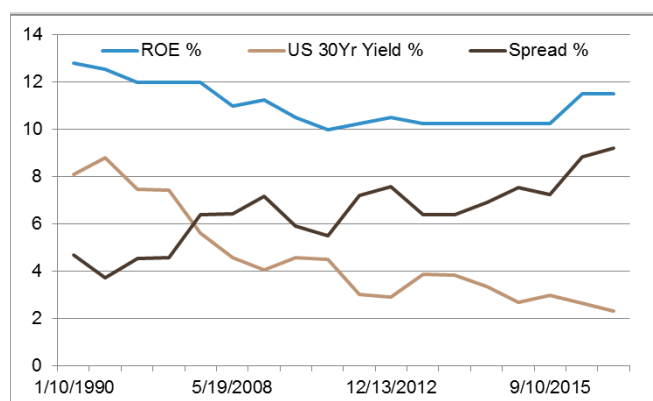
Following the latest decline in US treasury rates we now see a greater risk of ROE erosion in the current rate case.

Figure 156: FPL Preliminary Rate Request

Year	Revenue Req. (\$Mn)	Inflation
2017	\$866	8.2%
2018	\$262	2.3%
2019	\$209	1.7%
2020	\$0	0.0%
Total	1337	12.2%
Average	\$334	3.1%
2013-2015 Avg. Requested ROE		10.50%
2013-2015 Avg. Approved ROE		9.86%
Current Avg. Pending Requested ROE		10.45%
Current FPL Requested ROE		11.50%

Source: Company filings, SNL Energy, UBS

Figure 157: Authorized Florida ROEs vs. 30Yr US Treasuries



Source: SNL Energy, FactSet

Although Florida has consistently granted ROEs that are above the national average, we do see some risk of authorized ROE erosion as 30-year US treasury yields have declined towards 2%. Helping NextEra is that the annual bill increase is modest (~3-4%) and that the company has had top-tier performance and continues to have the lowest bills in the state.

Even with a satisfactory ratecase outcome, NEE might not earn at the top of its ROE band *initially* as management expects it could take a couple years to drive O&M savings yet again as the latest round of savings will be recaptured in the ratecase.

In its testimony the Public Counsel recommended an 8.75% ROE – [details are here](#).

What is the timeframe expected? Intervenors submitted testimony in mid-July.

- August 8th: Rebuttal testimony
- August 22nd: Hearings scheduled
- September 12th: Briefs due
- October 14th: PSC Staff recommendation
- October 27th: PSC vote expected
- January 2017: New rates effective

Is a settlement possible? Management reiterated its openness in our meeting.

With few controversial issues we think a **ratecase** settlement is a distinct possibility again. FPL reiterated that it is open to another multi-year settlement but four years would likely be the longest duration it was comfortable with given the interest rate. If a settlement is likely it would likely occur in early-to-mid 3Q15 (July/August), prior to hearings. In the last **ratecase** FPL (Docket 120015) offered a settlement in mid-August 2012.

NEE has a track record of settling ratecases: 5 multi-year settlements have been struck over the last 17-years

How will the Office of Public Counsel influence the process?

In the previous **ratecase** the Florida Office of Public Counsel (Public Counsel) was not a party to the settlement and challenged the settlement to the Florida Supreme Court making a litany of arguments. The Florida Supreme Court issued a lengthy opinion denying the Public Counsel's arguments. NextEra is hopeful that it can have productive conversation with the Public Counsel as it did on the recent Cedar Bay settlement. As mentioned, the Public Counsel's ROE recommendation is significantly lower than NextEra's request but it is not uncommon for there to be a large 'spread' between pro-consumer groups and the utilities.

- **How will management respond to latest gas reserve setback?** On May 19th the Florida Supreme Court ruled 6-1 against NextEra Energy (NEE) in its program to invest in natural gas reserves. Originally NextEra received approval from the Florida Public Service Commission (PSC) to pursue upwards of \$500Mn of annual investment in ratebase gas reserves. The essence of the Court's opinion was that authoring the investment in natural gas reserves with a regulated rate of return was beyond the authorization scope of the Florida PSC and would require legislative approval. The first \$191Mn pilot (Woodford) is currently underwater in the near-term based on filings from 4Q15 given sharp declines in the gas environment. According to a fuel recovery clause filing made with the Florida PSC, FP&L stated that its investments in shale gas

reserves in Oklahoma's Woodford Shale will not translate into customer savings over the first year vs. a scenario where it simply bought gas in the spot market. In the first year (2015), these investments are expected to rather cost the customers \$5.8mn and overall customer savings over the 50-year life of the project were last expected to be ~\$49mn vs. initial estimates for customer savings of more than \$100Mn.

This ruling is the latest strike against gas reserve investments in ratebase as regulators and consumer advocates have been critical of all fuel hedging efforts given the multi-year negative trends in commodity costs. While the majority of investors have not included any benefit from gas ratebasing opportunities based on our conversations, this reduces the probability of this being a viable regulated investment in the future. (Florida PSC Docket 150001-EI)

Updated EPS Estimates

Below we present our adjusted EPS estimates which are substantially the same following our extensive 1Q16 update here with only minor adjustments for commodities.

Figure 158: NextEra EPS Estimates

EPS - Segments	2013A	2014A	2015A	2016E	2017E	2018E
FP&L	3.16	3.45	3.63	3.79	3.92	3.92
NEER	1.83	1.89	2.04	2.53	2.84	3.20
Corporate & Other	(0.02)	(0.04)	0.06	0.00	0.00	0.00
Total UBSe	4.97	5.30	5.72	6.32	6.77	7.12
UBSe (Prior)	4.97	5.30	5.72	6.32	6.75	7.09
Consensus		5.30	5.71	6.18	6.56	7.01
Company Guidance				\$5.85-\$6.35		\$6.60-\$7.10

Source: Company filings, FactSet, UBS estimates

Valuation: Increase Price Target \$6 to \$140

Our valuation remains based on a 2018 sum-of-the-parts analysis. The higher valuation remains the unregulated side of the business where we have refined our debt assumptions, performed a commodities mark-to-market, and reflect the ~10% improvement in NEP shares since May – all of which are favorable updates.

Figure 159: NEE Sum-of-the-Parts Valuation

NextEra Energy Inc. Valuation									
	2018E Adj. EBITDA	'17 Guidance	EV/EBITDA & P/E Multiple			Enterprise Value			
NextEra Energy Resources (NEER): EV / EBITDA			Low	Base	High	Low	Base	High	
Merchant Portfolio	613	500-620	7.0x	8.0x	9.0x	4,289	4,902	5,515	
Less: Texas Hedges	(70)		7.0x	8.0x	9.0x	(490)	(560)	(630)	
Upstream/Midstream	243	190-290	4.0x	5.0x	6.0x	970	1,213	1,456	
Power & Gas Trading	100	75-115	4.0x	5.0x	6.0x	399	499	599	
Customer Supply	157	135-195	4.0x	5.0x	6.0x	627	784	940	
Contracted Nuclear	288	330-340	8.0x	9.0x	10.0x	2,307	2,595	2,884	
Contracted Renewables	2,876	2,525-3,125	9.0x	10.0x	11.0x	25,886	28,763	31,639	
Plus: Tax Credits	1,210	1,175-1,305	7.0x	8.0x	9.0x	8,467	9,677	10,886	
Less: NEP Consolidated	(700)	640-760	9.0x	10.0x	11.0x	(6,300)	(7,000)	(7,700)	
Contracted Other	47		7.0x	8.0x	9.0x	331	378	425	
Total / Implied (ex-ITC)	4,763		7.7x	8.7x	9.7x	36,488	41,251	46,015	
Add: NPV of Pipeline Projects (Sabal Trail, Mountain Valley Project, etc.)						1,527	1,697	1,866	
Add: 2019/2020 NPV of Solar and Wind Expectations						607	675	742	
Add: NPV of Texas Hedge						314	349	384	
Less: Total NextEra Net Debt						(35,540)	(35,540)	(35,540)	
Less: FP&L Debt						13,984	13,984	13,984	
Less: Transmission, Pipeline, & Other						2,016	2,016	2,016	
Less: NEP Debt						3,435	3,435	3,435	
Less: Net NEE Resources Debt						(16,105)	(16,105)	(16,105)	
NextEra Energy Resources						20,383	27,867	32,631	
Shares Outstanding (2018E)						455	455	455	
NextEra Energy Resources Value per Share						\$44.79	\$61.24	\$71.71	
NextEra Utilities: P/E Multiple	2018E NI	Low	Peer	Premium	Base	High	Low	Base	High
Florida Power & Light	1,784	16.8x	16.8x	1.0x	17.8x	18.8x	29,979	31,763	33,548
NextEra Transmission	34	16.8x	16.8x	2.0x	18.8x	19.8x	565	632	666
Total Utility	1,818	16.8x			17.8x	18.8x	30,544	32,396	34,214
Shares Outstanding (2018E)							455	455	455
NextEra Utilities Value per Share							\$67.12	\$71.19	\$75.19
NextEra Energy Partners (NEP): Ownership Stake			Low	Base	High		Low	Base	High
LP Value per Share			25	28	31		\$5.62	\$6.24	\$6.87
GP Value per Share (IDRs)							\$0.00	\$1.02	\$3.26
NEP Value per Share							\$5.62	\$7.26	\$10.12
Total Equity Value per Share							\$118.00	\$140.00	\$157.00

Source: Company filings, FactSet, UBS estimates

NRG Energy Inc.

As attention grows on the GenOn negotiation process, management has stated that it will be disciplined when dealing with creditors and will seek to preserve its balance sheet while working to offset dis-synergies.

We forecast NRG Energy reporting 2Q16 adjusted EBITDA of **\$668 Mn**, modestly behind Street consensus (~\$683Mn). Hedges are rolling off in the Northeast, which means results are likely to be impacted in addition to the Gulf. We suspect mild weather likely drove resilient Retail. We do not expect a shift in guidance either, albeit acknowledge that mild weather could yet place a broader negative bias on FY16 results.

We look for discussion on GenOn restructuring, a plan on the GreenCo biz to come with a more mixed reception as investors wait for action on achieving the debt reduction plan

Figure 160: NRG 2Q Results Adj. EBITDA Comparison

NRG Energy Adjusted EBITDA (\$Mn)	1Q15A	2Q15A	1Q16A	2Q16E	2Q +/-	UBSe FY16	NRG 2016 Guidance *	2015A
Business								
East	182	144	245	129	(15)	541		1,057
Gulf Coast	91	115	123	95	(20)	321		588
West	(8)	20	55	30	10	107		102
Business Total	265	276	423	254	(22)	969		1,738
NYLD	122	187	188	242	55	803	805	-
Corporate and Other	281	53	44	(21)	(74)	692		926
Wholesale - Total	387	463	611	496	33	1,772	1545-1670	1,738
Retail Businesses	172	213	151	253	40	653	\$650-\$725	653
Adjusted EBITDA	840	729	806	728	(2)	3,116	3,000-3,200	3,316
Street Mean EBITDA Est.				683			3,089	

Source: Company reports, ThomsonReuters, UBS estimates

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

[6/9/16: Gen Off? Downgrade to Sell](#)

[5/19/16: Selling the Northern Lights](#)

[5/18/16: NYLD: Equity-less Drop](#)

[5/5/16: Sprucing Up the Portfolio](#)

[3/9/2016: Explaining the Path Forward](#)

[1/14/2016: NYLD: Darkest Before Dawn](#)

[12/18/2015: NYLD: What Will NRG Do With Its YieldCo?](#)

[12/18/2015: Digging Deep to Find Value](#)

[12/2/2015: Lightning Up at GenOn](#)

What are the key updates for NRG?

- **Mauricio's Three Key Sayings:** Recently anointed CEO has three key pillars of the NRG equity story on which he is focusing the story: 1) Simplification, primarily addressing GenOn; 2) Protecting the Balance Sheet, including paying down medium term maturities; and 3) Creating Value for All Stakeholders, including creditors at GenOn and elsewhere within the Capital Structure.
- **Reducing Costs All Around:** With the 2Q update the first since the latest PJM capacity auction, we expect updates on coal assets here too. We emphasize the outlook suggests an effort to reduce costs and effectively harvest assets. Cost reductions could yet help alleviate pressures at both GenOn as well as the wider entity. This could be a positive factor for ~2017 estimates with 2Q. This reduction in investment in peripheral plants is consistent with the strategy on improving FCF with a step-up in capex in 2017.
- **Pushing out remaining debt obligations:** We look for more debt reduction through the near term, largely pushing out all debt through 2020. Of the ~\$5

Bn in maturities, there is just \$518 Mn in 2018 left. This too is likely to be addressed in the near-term to fully execute on management's stated plan.

- **Running through the GenOn Dynamics:** NRG stated on its 1Q16 earnings call that it would negotiate with GenOn creditors in the near term and according to media reports NRG plans to hire a restructuring advisor to help in the efforts. The most significant uncertainty continues to revolve around the outlook for the non-recourse GenOn subsidiary. Raising \$491Mn of proceeds from asset sales will help facilitate the negotiation but there is still \$1.34Bn of obligations due in 2017/2018 that need to be addressed.
- **Legacy services arrangement is a key area of attention:** We expect the dynamic between creditors and management to intensify in coming months as focus on restructuring options for the highly-leveraged but non-recourse subsidiary grows. We emphasize management appears poised to pursue further asset sales in coming periods, likely including one or two CCGTs as part of efforts to raise liquidity to address the 2017 maturity. We expect creditors to push for a reduction in the size of its services payments back to the NRG Energy parent, with the current \$193Mn based on pre-2013 cost structure but GenOn now owns 25-30% less capacity. Mgmt is quite confident it largely offset any loss of the business.

Discussions on the equity remain focused on how large this payment would be. Management did not elaborate on any plans around this—or any other tangible strategies at GenOn. We see a reduction in the G&A payment at least proportionate with the asset sales, if not materially more. The Street expectation for the new services payment is a wide range of \$50-\$150Mn but is consistently materially lower. We emphasize the dynamic between the parent and GEN subsidiary could become more contentious as focus swirls around bidding practices in energy and capacity markets, as well as focus on the transfer of assets between the subsidiary and the parent (ex. leasing land to NRG for new Mandalay and Canal constructions). The claim appears to be that the GenOn acquisition was structured to effectively extract cash from the subsidiary via 'above-market' services arrangements, rather than 'at-cost'.

- **What kind of combination would be palatable for a restructuring for NRG?** NRG continues to look at any kind of restructuring with GenOn as closely focused on maintaining reasonable credit metrics back at NRG Corp. As a consequence, the objective would be to limited recourse debt to 4.25x adjusted EBITDA. With GenOn seemingly north of 9x+ Debt/EBITDA using the valuation framework below, we expect that any exchange offer back to the parent would include a combination of debt and NRG common equity (or equivalent). Even assume the portfolio is acquired at a valuation of 6-7x EBITDA (below current trading value of bonds), this could still involve ~\$600 Mn - \$1Bn in total common equity (\$2/sh or more not yet reflected in our valuation) assuming just 4x Debt/EBITDA is exchanged in the form of NRG debt.
- **Other Genon subsidiaries will eventually need addressing as well:** Further, with negligible value from the REMA and Mid-Atlantic leases regardless, we see a potential view that little in terms of cost allocation 'benefits' should be paid to GenOn Corp creditors (seeing they are still subordinated to these further layers of leverage). Bottom line, addressing

We emphasize management appears poised to pursue additional asset sales in coming periods, likely including one or two CCGTs as part of efforts to raise liquidity to address the 2017 maturity.

We believe the intercompany support agreement could be renegotiated lower in the future following the recent asset sales and retirements.

This remains the primary overhang on the stock beyond restructuring events.

Further, we see other risks relating to NRG's relationship with GenOn including tax attribution (NOL benefits) and contracting/retail commitments

How does a GenOn restructuring resolve itself?

NRG has stated that it would try to manage the GenOn situation to protect the NRG Corp balance sheet and maintain value for equity holders.

the GenOn HoldCo notes is just the start. Moreover, dissynergies potentially lost from retirements and loss of assets at these levels only add to the GenOn risk and timeline in future years.

- **Secured debt capacity at GenOn:** Among the key levers remaining to address the forthcoming maturity in 2017 is untapped secured debt capacity which management has estimated at ~\$700Mn at the GenOn Corp level and a further \$200Mn at the GenOn Mid-Atlantic Generation (GAG) level. Given the challenging outlook we believe adding even secured debt could be an issue with a negative FCF profile. We emphasize even paying down 2017 with existing liquidity, 2018 is still likely the key challenge.
- **Is there risk between the NRG and GenOn Corp Structure?:** We note some investors of late have been focusing their efforts on this angle. While difficult to assess given the explicit structuring at the time of the GenOn acquisition to ensure a continued structural separation between the two entities (and without any formal distributions ever), there are a few clear datapoints to suggest this is the case. We note Tim Toy, a legal expert, and others have pointed to the discrepancy between the 36th indenture and the base indenture with respect to acceleration of liabilities due at *all* subsidiaries vs. *unrestricted* subsidiaries. We suspect additional focus may grow around this nuance in coming months as the ongoing restructuring conversations continue between creditors and NRG management.
- **No New Equity:** Mgmt does not see an outcome in which NRG equity would be paid for the GenOn assets. With a goal of maintaining holding company leverage at 4.25x at the parent, this could imply debt at ~50c, relative to the ~80c market value today. Bottom line, we think mgmt is effectively saying they will not negotiate with lenders unless at a substantial discount.
- **Addressing the discount sooner than later.** Given the clear indications in strategy that no new equity issuances would be palatable, we would not be surprised to see a readily executed decision on the GenOn business in months well ahead of the contemplated 2017 maturity.
- **Does NRG need GenOn for retail obligations? No.** Mgmt is increasingly clear it hedge its PJM risk via both its legacy PJM footprint as well as the EME portfolio it acquired several years ago. This portfolio, while located in NI Hub appears to offer sufficient generation exposure, albeit there appears a clear basis exposure within the footprint. Bottom line, we don't perceive the generation alignment with retail as forcing mgmt to maintain the biz through any restructuring of this highly leveraged subsidiary.
- **De-emphasizing PJM footprint:** We perceive mgmt as focused on talking down expectations for the core PJM footprint, particularly into any potential filing of its GenOn business. Rather, the core of the business remains the NI Hub market with the EME portfolio (and uplift from recent nuclear retirements), the retail business (and meaningful FCF contributions), as well as dividends from its NYLD business and other 'to-be-dropped' renewable assets.

Has the 36th indenture *replaced* the Base?

Management is confident on the ringfencing.

- **NYLD: Restarting the ROFO Pipeline & More:** We think the most likely outcome for NYLD is largely status quo in relation to NRG; rather than scaling back we anticipate NRG is poised to ramp back *up* its efforts with respect to NYLD. In particular, we see a delineation of a wider ROFO pipeline as well as potential independent ROFO arrangements as likely next steps with Chris Sotos now as the independent CEO of the organization. We reiterate NYLD as our preferred YieldCo idea.

We reiterate our overall preference for this sector amidst a declining interest rate environment. We emphasize project debt terms continue to decline in costs and spreads for the sector, with recent deals swapped into ~4% term paper. We look towards levered YieldCos to discuss this improvement in their financing prospects.

- **Just how much CAFD could be generated from CVSR?** We emphasize that the available CAFD could be as low as ~single digit millions by the time debt amortization and interest expense is accounted for depending on the magnitude of debt and amortization profile assuming entirely debt financed (CVSR would also transfer \$398Mn of project level debt).
- **Aurora Asset Sale Latest; Don't Expect Others Like This:** Below we show the mini-model for the Aurora asset with no real energy margin and all of the economic value derived via capacity payments. Even based on [our assumption that capacity prices will increase to \\$225/MW-Day in the upcoming 2019/2020 Capacity Auction](#) there is no material impact on the plant compared with the \$215/MW-Day price in the last auction; however, if capacity prices decline towards the RTO level (\$160/MW-Day or lower) we believe this would significantly reduce the free cash flow profile of the asset. Further, given the limited run times capacity performance (CP) compliance risk is likely not trivial.

Using a 9.6% discount rate we estimate a \$260-\$310Mn NPV depending on the assumed useful asset life and keeping ComEd pricing constant into the 2020s.

We see NYLD as particularly well positioned into 2Q for ROFO updates and more

Figure 161: CVSR Drop Analysis

CVSR Drop (UBSe)	EBITDA	CAFD
Implied CVSR Guidance	55	25
Incremental Financing		(11)
Debt Assumed (\$Mn)	398	398
Equity to NRG (\$Mn)	150	200
Total EV	548	598
EV / EBITDA	10.0x	10.9x
Gross CAFD Yield (%)	17%	13%
Net CAFD Yield (%)	12%	9%
2Q16E Liquidity Walk (\$Mn)		
Unrestricted Cash 1Q16		76
Revolver Availability 1Q16		119
Plus: 2Q16E CAFD		66
Less: 2Q16E Dividend		(42)
Pre-CVSR Liquidity		219
Less: CVSR Midpoint		(175)
Plus: Estimated Project Debt		88
2Q16E Ending Liquidity		132

Source: Company Filings and UBS Estimates

How to make sense of the deal price?

The deal would appear consistent with similar transactions involving peaking facilities in the adjacent MISO market on continued and sustained capacity prices in this region. The purchase price for Aurora seemingly embeds a view on eventual nuclear plant retirements.

Figure 162: Aurora Generating Station Mini-Model

Aurora Peaker	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity	878	878	878	878	878	878	878	878	878	878
Capacity Factor, UBSe	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
NI-Hub Peak (\$/MWh)	39	38	34	35	35	33	34	34	35	35
Bias for Super-Peak ~50%	20	19	17	18	18	17	17	17	17	17
Heat Rate	12,370	12,475	12,475	12,475	12,475	12,475	12,475	12,475	12,475	12,475
Variable Cost (\$/MWh)	(57)	(35)	(35)	(40)	(40)	(42)	(42)	(42)	(42)	(42)
Energy Margin (\$/MWh)	2	23	16	13	12	8	9	9	10	10
Generation (TWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Energy Margin (\$Mn)	0	1	1	0	0	0	0	0	0	0
PJM ComEd Capacity Payment (\$/MW-day)	182	136	135	144	189	221	225	225	225	225
Capacity Revenue (\$Mn)	52	39	39	42	54	64	65	65	65	65
O&M (\$/kW-yr), UBSe	10	10	10	10	10	10	10	10	10	10
O&M (\$Mn)	9	9	9	9	8.78	9	9	9	9	9
EBITDAR	44	31	31	33	46	55	56	56	57	57
Less: Maintenance Capex (\$5kW-yr)	4	4	4	4	4	4	4	4	4	4
Less: Major Maintenance	-	-	-	-	-	-	-	-	-	-
Free Cash Flow	39	27	26	29	42	51	52	52	52	52
EV/EBITDA Multiple	9.3x	13.5x	13.9x	12.6x	8.8x	7.2x	7.0x	7.0x	7.0x	7.0x
NPV 15Yr	306	NPV / 2018 EBITDA			9.2x	NPV \$/kW			348	
NPV 10Yr	264	NPV / 2018 EBITDA			7.9x	NPV \$/kW			300	

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

How does this compare versus the other deals?

The Aurora divestiture will generate significantly more value than the 4Q15 transactions and represents a substantial premium to the other Illinois transaction (Shelby) recently executed.

The real remaining asset with a potentially big multiple sale: We emphasize that we do *not* expect any further deals quite like this one. The most important remaining asset sale within the portfolio is clearly the 800MW Choctaw CCGT, however there have been developments to indicate a sale to its local utility, Entergy.

Figure 163: Recent GenOn Divestitures

Divested Asset	MW	Fuel	Region	Price (\$Mn)	\$/kW
Seward	525	Coal	Pennsylvania	\$75	\$143
Shelby County	352	Gas	Illinois	\$46	\$131
Aurora	878	Gas	Illinois	\$365	\$416
Total	1,755			\$486	\$277

Source: Company Filings

Latest MtM Outlook

We include our latest look at forward EBITDA estimates. We do not expect management to revise its consolidated EBITDA guidance but do expect further updates on long-term cost reductions.

Figure 164: Updated NRG Energy Adjusted EBITDA Estimates

NRG Energy EBITDA (\$Mn)	2015A	2016E	2017E	2018E	2019E	2020E
<i>NYMEX Assumption</i>	2.51	2.51	3.16	3.04	3.17	3.17
Texas	470	187	82	64	84	13
South Central	118	134	117	139	140	116
Northeast	1,033	531	380	436	405	365
West	102	107	114	96	98	98
NYLD Eligible	171	225	233	311	311	348
Renew						
NYLD	720	803	801	800	799	799
<i>Guidance</i>	705	805				
B2B						
Home						
Retail Businesses	739	653	651	683	682	715
<i>Home Guidance</i>	700-750	650-725				
Corporate, Other, and Unallocated Synergies	(37)	467	537	537	537	537
NRG Adj. EBITDA (UBSe)	3,316	3,105	2,915	3,065	3,056	2,991
<i>Prior EBITDA Est. (UBSe)</i>	3,397	3,113	2,944	3,068	3,065	
Consensus EBITDA Est. (5/31/16)	3,235	3,103	2,822	3,012	2,913	
Guidance (1Q16)	\$3,250-\$3,350	\$3,000-\$3,200				

Source: Company Filings, ThomsonReuters, and UBS Estimates

Valuation: Dropping PT to \$15 from \$16

We include our latest valuation below; our changes below reflecting:

1. Latest shifts in commodity MtM (+\$1/sh), including better rail terms to Texas and the Southeast on the back of reduced pricing discussion regionally.
2. Impact from GenOn dis-synergies: In an effort to fully capture the potential negative, we are assuming the loss of GenOn and the immediate loss of ~\$50 Mn in dis-synergies. Mgmt's latest guidance suggests the lost allocations can be 'substantially' offset.
We flag among the key assumptions we have made is the fact that GenOn is non-recourse and hence removed from our valuation. This is consistent with our treatment of DYN's IPH subsidiary now of late as well.

Figure 165: NRG Energy Valuation: Slightly Tweaked Lower

NRG Energy Valuation		2018 EBITDAR		EV/EBITDA Multiple			Enterprise Value (\$Mn)		
		Low	Prem/ Discount	Base	High	Low	Base	High	
NRG Energy (Classic) and GenOn									
Base IPP Multiple =				7.0x					
Texas	64	6.0x	0.0x	7.0x	8.0x	382	446	509	
Northeast	178	6.0x	0.0x	7.0x	8.0x	1,067	1,245	1,422	
GenOn Operating Leases	80	5.0x	-1.0x	6.0x	7.0x	400	480	560	
South Central	139	6.0x	0.0x	7.0x	8.0x	834	973	1,113	
West (All-Inclusive)	96	4.0x	-2.0x	5.0x	6.0x	385	481	577	
Renew (Ex-Ivanpah)	281	9.0x	3.0x	10.0x	11.0x	2,529	2,810	3,091	
Retail Businesses (Reliant, GM, E+, D)	683	5.0x	-1.0x	6.0x	7.0x	3,415	4,098	4,781	
Edison Mission									
EME - MidWest Generation	228	6.0x	0.0x	7.0x	8.0x	1,369	1,597	1,825	
EME - EMMT (Trading)	32	5.0x	-1.0x	6.0x	7.0x	158	189	221	
EME - Other (Gas and Other)	68	6.0x	0.0x	7.0x	8.0x	408	476	544	
Other, Corporate, and Unallocated Synergies	523	6.0x	0.0x	7.0x	8.0x	3,135	3,658	4,180	
Total / Implied	2,371	5.9x	-0.1x	6.9x	7.9x	14,082	16,453	18,824	
Net Debt and Other: 12/31/15									
NRG Recourse Debt						(8,586)	(8,586)	(8,879)	
GenOn Non-Recourse Debt						(2,584)	(2,584)	(2,003)	
GenOn and EME PV Operating Leases						(1,154)	(1,154)	(1,154)	
Other Conventional Debt (Non-Recourse)						(85)	(85)	(85)	
Solar Non-Recourse Debt (Ex. Ivanpah)						(1,731)	(1,731)	(1,731)	
Preferred Shares						(331)	(331)	(331)	
Pending Asset Sales						426	426	426	
Cash						1,358	1,358	1,358	
Add: NRG Yield Home Solar ~93MWs (YE15) @ \$0.15 CAFD/Watt @ 10% discount rate						140	140	140	
NPV of Equity using Hedged EBITDA Methodology						1,535	3,906	6,565	
Open Analysis									
Power Hedges	(185)	5.9x		6.9x	7.9x	(1,100)	(1,285)	(1,470)	
Total						(1,100)	(1,285)	(1,470)	
add NPV of Power Hedges							349		
NPV of Equity using Open EBITDA Methodology						784	2,970	5,444	
GenOn Add Back of Neg Equity Value						\$3.20	\$2.95	-	
Add: GenOn Loss from Synergies (~\$50 Mn @ Base Multiple)						-\$0.95	-\$1.11	-	
NYLD Class A & C Average Share Price						13.46	14.96	16.46	
NYLD Equity Value						1,150	1,278	1,405	
\$/share for NRG Energy (85Mn Shares Owned (B & D))						3.65	4.06	4.46	
Estimated 2018 Shares Outstanding						315	315	315	
Equity value per share (using Avg of Open/Hedged)						\$8.00	\$15.00	\$22.00	

Source: Company filings, UBS estimates

NRG Consolidated FCF (both incl/excl NYLD and GenOn)

Figure 166: NRG FCF Projections

EBITDA to Cash Flow Analysis	2015	2016	2017	2018	2019	2020
NRG:						
Consolidated EBITDA	3,340	3,105	2,915	3,065	3,056	2,991
Interest Expense	(1,158)	(1,400)	(1,412)	(1,363)	(1,220)	(1,149)
Income Tax	-	-	-	-	-	-
Collateral / Working Capital	(685)	(26)	25	165	2	9
Other / Deferred Taxes	(15)	477	353	274	295	331
Less: Home Solar	(173)	(100)				
CFO	1,309	2,057	1,882	2,140	2,133	2,183
Maintenance Capex	(413)	(475)	(375)	(375)	(375)	(375)
Environmental Capex	(237)	(250)	(5)	(15)	(20)	(25)
Other (Collateral Adjustment)	477					
Preferred Dividend	(9)	(9)	(9)	(9)	(9)	(9)
FCF Pre-Growth Capex	1,127	1,323	1,493	1,741	1,729	1,774
Guidance	1,100-1,300	1,000-1,200				
Amortization Schedule - Non-NYLD						
Agua Caliente	28	29	30	31	31	32
CVSR	25	25	26	27	28	29
Viento	22	23	23	24	25	26
NRG Peaker	20	20	20	20	21	21
Cedro Hill	8	9	9	9	9	10
NRG - Other	19	19	20	21	21	22
Debt Amortization	121	124	128	132	135	93
Adjusting for NRG Yield						
NRG Yield EBITDA	(720)	(803)	(801)	(800)	(799)	(799)
Cash Interest Paid	234	234	234	234	234	234
Net NRG Yield Consolidation Adjustment	(486)	(569)	(567)	(566)	(565)	(565)
Dividends from NRG Yield Ownership	71	81	91	102	107	107
Total NYLD Adjustment	(415)	(488)	(476)	(464)	(459)	(459)
Adjusting for GenOn Energy	(255)	(359)	(252)	(148)	(241)	(233)
Total NRG Free Cash Flow	833	959	1,145	1,409	1,406	1,408
		750-950				
Market Cap	4,891	4,891	4,891	4,891	4,891	4,891
Less NYLD Stake	1,203	1,203	1,203	1,203	1,203	1,203
Market Cap (ex-NYLD)	3,687	3,687	3,687	3,687	3,687	3,687
Implied FCF Yield (with NYLD)	17%	20%	23%	29%	29%	29%
Implied FCF Yield (without NYLD)	23%	26%	31%	38%	38%	38%
GenOn EBITDA						
Interest Expense	(202)	(239)	(239)	(239)	(239)	(239)
Maintenance Capex	139	152	94	82	82	82
Environmental Capex	36	62	-	-	-	-
Total Capex	254	334	100	86	82	82
Free Cash Flow (Pre-Leveraged Lease)	53	(259)	(156)	(99)	(148)	(183)
Net Leveraged Lease Impact (Debt A)	(86)	(100)	(96)	(49)	(93)	(50)
Free Cash Flow (Pre-Leveraged Lease)	(255)	(359)	(252)	(148)	(241)	(233)
Uses						
Organic Growth Capital	900	500	500	-	-	-
Total Capex	1583	1,225	880	390	395	400
Assumed Share Repurchases	(1)	-	-	-	-	-
Projected Common Dividend	201	74	38	38	38	38
Remaining for Debt Paydown, etc.	(656)	24	575	1,313	1,296	1,336

Source: Company reports, UBS estimates

GenOn Outlook: A Tad Brighter

We include our outlook on GenOn applying a base multiple of 7.0x across the NRG universe, but applying discounted multiples to the PJM assets, as noted below.

Our latest update also removes the PJM East DCF. Following confirmation from a variety of parties the PJM East portfolio will likely continue to operate beyond the 2020 implementation of Phase 2 of the Maryland Healthy Air Act regulations *without* meaningful capital we are returning to putting a multiple on the business rather than simply a 5-year DCF. We emphasize the lower 6x multiple on near-year EBITDA does not driven a materially better outlook.

We're comfortable Dickerson, Morgantown, and Chalk Point will survive MD HAA under Gov Hogan in Maryland

Figure 167: Updated GenOn Subsidiary Valuation

GenOn Energy	2018 EBITDA	EV/EBITDA Multiple				Enterprise Value (\$Mn)		
<u>GenOn Mini-Model SOP Valuation</u>		Low	Discount	Base	High	Low	Base	High
Eastern PJM	32	5.0x	-1.0x	6.0x	7.0x	161	193	225
Western PJM/MISO	86	5.0x	-1.0x	6.0x	7.0x	431	518	604
California	27	4.0x	-2.0x	5.0x	6.0x	106	133	159
Other (New England, NY etc.)	88	6.0x	0.0x	7.0x	8.0x	530	619	707
Energy Marketing/Gas Contracts	(8)	5.0x	-1.0x	6.0x	7.0x	(40)	(48)	(56)
GenOn EBITDA	225	5.3x		6.3x	7.3x	1,189	1,414	1,639
GenOn Operating Leases	80	5.0x	0.0x	6.0x	7.0x	400	480	560
GenOn EBITDAR	305	5.2x		6.2x	7.2x	1,589	1,894	2,199
Net Debt and Other: 12/31/15								
GenOn Senior Notes						(1,830)	(1,830)	(1,418)
GenOn Americas and Other						(754)	(754)	(584)
PV of GenOn Mid-Atlantic Operating Lease						(672)	(672)	(672)
PV of REMA Operating Lease						(376)	(376)	(376)
Pending Asset Sales						370	370	370
Cash (12/31/15)						665	665	665
Net Equity Value to NRG Corp						(1,008)	(703)	184
Net Equity Value to NRG Corp (per Share)						-\$3.20	-\$2.23	\$0.58
Implied 'Fully Loaded' Net Debt & Leases/EBITDA							8.5x	

Source: Company filings, Platts, UBS estimates

PG&E Corporation

PCG continues to have an above-average risk profile today but we see a path towards real improvement as the company progresses through some of the more critical regulatory issues. For example, the possibility of a settlement in the 2017 General Rate Case (GRC) in coming weeks could meaningfully reduce regulatory risk. While the Butte fire, Diablo Canyon retirement, and San Bruno criminal cases are overhangs, the company is slowly moving in the right direction on a risk front; we believe investors underestimate the risk of the latest Diablo Canyon deal risk. Ultimately we believe a discount to local peers is warranted, investors could continue to flock to the less expensive utilities amidst the latest group outperformance.

We forecast 2Q16 adjusted EPS of **\$0.86** vs \$0.91 in 2Q15 and \$0.100 Consensus.

- **Key Drivers:** Growth in ratebase forms the foundation for PCG earnings but in 2Q16 this is offset by the impact of a nuclear refuelling outage. Consensus is seemingly including estimates which have retroactive GT&S revenue
- **Wildcard Factors:** (1) Recognition of GT&S revenue [see below]; (2) miscellaneous items which have ranged from +/- \$0.09 historically; and (3) timing of taxes which largely nets-out for the full year but introduces additional uncertainty

Figure 168: PCG 2Q16E Earnings Walk

PG&E Corp. 2Q16 Earnings Walk	EPS
2Q15A Adjusted EPS	\$0.91
Growth in Ratebase Earnings	0.05
Timing of Taxes	(0.03)
Disposition of SolarCity Stock	0.00
Nuclear Refueling Outages	(0.05)
Timing of GT&S Cost Recovery: 4Q Item?	-
Regulatory and Legal Matters	(0.02)
Energy Efficiency Incentive Revenues	0.00
Miscellaneous	0.03
Dilution	(0.03)
2Q16E Adjusted EPS	\$0.86
2Q16 Consensus	\$1.00
2016 UBSe EPS	\$3.74
2016 Consensus	\$3.72
2016 Guidance	\$3.65-\$3.85

Source: Company Filings, FactSet, and UBS Estimates

Management is included the higher earnings from the GT&S case in its 2016E guidance; however, the timing is unclear for earnings recognition. On its 4Q16 earnings call PCG indicated that it would record the 2016 retroactive GT&S earnings after a final decision was received (2015 earnings would be excluded from operating earnings). Given the uncertainty in the alternative proposed decision, we expect management to wait until the final order is received before recognizing the associated revenues. A final decision is expected within 90-days of the alternative proposed decision (October 12th).

We are increasingly positive on California overall as the 'value' play on the utility sector

When PCG received the 'final-final' decision in the GT&S case it can record substantially all of the retroactive catch-up except for the 36-month window for amortization.

PCG includes a "reasonable outcome" in the GT&S rate case in its 2016 guidance.

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

[6/29/16 Finding a New Groove](#)

[5/23/16 Raising the Dividend and Ending an Era](#)

[5/6/16 A Good Decision for GT&S](#)

[5/5/16 Biting off a Bit More Equity for Butte](#)

[2/19/16 Still a Full Plate for 2016](#)

[1/29/16 Holding Our Horses](#)

[10/29/15 Still Waiting for Resolution](#)

[7/30/15 Pushing it Out](#)

What are the key updates for PCG?

- **GT&S alternative proposed decision gives more clarity but final decision could take until October:** PG&E received a revised alternate proposed decision (PD) on June 23rd in the 2015 Gas Transmission and Storage (GT&S) rate case which still includes key variables. The outcome is more nuanced but broadly clears the decks on its largest regulatory item. On one hand the proposed decision has ~\$700Mn of additional capex removed from the 2011-2014 period but \$576Mn of that spending could ultimately be approved at a later date. Conversely the treatment of the \$850Mn San Bruno penalty could vary with a capex disallowance impacting the long-term earnings power of the company whereas expense treatment could result in material immediate customer savings (yet maintain PG&E ratebase prospects). These two points are contrasting to management's latest ratebase projections with its 8K disclosure.

PCG's 2016 weighted average ratebase guidance for gas transmission is \$3.0-\$3.4Bn which assumed (1) the San Bruno penalty was treated predominately as shareholder-funded capital expenditures [~\$689Mn] – i.e. lower rate base and (2) recoverability of \$696Mn of 2011-2014 excess capex above the 2011 GT&S decision. If the San Bruno penalty is treated as an expense rather than disallowed capex we think these two items could offset with minimal net impact to 2016 ratebase; we emphasize the high degree of uncertainty. A further complicating factor is that the **ex-parte penalty is variable** and calculated as five months (42%) of the annual revenue requirement after adjusting for the San Bruno penalty. As a result, if more of the San Bruno penalty is shifted towards expense classification, this would reduce the ex-parte penalty (double benefit). We would expect this to be a potentially positive near-term revision. The customer rate impact delta is 6% vs 16% making expensing a political expedient option.

Further clarity should be available in the fall: briefs are due July 7th with reply briefs due July 14th and a decision expected within 90-days (October 12th); however, PG&E can implement interim rates on August 1st. Further, audit proceeding on capex spent above the allowable GRC levels in last rate case period (2011-2014) could yet take some time – suggesting this could be a future reduction (full recovery is assumed at top end of ratebase guidance range, taking below the range if fully lost). The 2011-2013 spending audit will begin as soon as is practicable but no clear timeline exists yet.

How does the GT&S revised alternate proposed decision impact the earnings outlook? PC&G has had a busy summer but we believe the company has made positive strides lately.

Fine: Will this be a reduction to ratebase or expensed. We believe this would be a lower impact on consumers if immediately expensed (to limit rate shock), but this would conversely help PG&E.

Audit for 2011-2014 capex above GRC levels: Remains a medium – dated overhang on ratebase.

Figure 169: Pacific Gas & Electric Company 2015 Gas Transmission & Storage Rate Case

Pacific Gas & Electric Company 2015 Gas Transmission & Storage Rate Case					
	2014	2015	2016	2017	2018
PCG Requested Revenue Requirement	548	1,263	1,346	1,488	N/A
Adopted Revenue Requirement	715	1,046	1,110	1,220	1,324
Less: San Bruno (SB) Penalty Estimate		850	Maximum		
Less: Ex-Parte Penalty Placeholder		(138)	Subject to change based on SB		
Revenue Requirement pre-SB penalty		908	1,110	1,220	1,324
Proposed Decision Revenue Requirement		1,109	1,183	1,309	
<i>Delta vs Adopted Revenue Req. (Not Comparable)</i>		(63)	(73)	(89)	N/A
Approved Annual Attrition Increase		331	64	110	104
Requested Annual Attrition Increase			83	142	
Actual GTS Revenue		550			
Annual Capex Midpoint		750	750	750	750
Weighted Average Ratebase Excluding San Bruno		2,900	3,300	3,600	4,200
1Q Guidance <u>Including San Bruno</u>			3,000-3,400		
2011-2014 Capex Disallowed Permanently		120			
2011-2014 Capex Subject to Audit		576			
2011-2014 Capex Removed		696	Included in guidance		

Source: Company Filings and UBS Estimates

- **Criminal Case is yet another near-term headline risk:** Separately the San Bruno federal criminal proceedings are underway where federal prosecutors have argued that the company intentionally utilized a loophole in the pipeline standard which led to the explosion and eight deaths. PG&E is charged with obstruction of the National Transportation Safety Board (NTSB) investigation and twelve violations of the Natural Gas Pipeline Safety Act (NGPSA). The original 2014 indictment charged the company with 27 violations. Any penalties in the federal case are separate from the state penalties. Federal prosecutors are seeking an alternate fine of \$562Mn compared with a \$1.1Bn original alternative penalty and the statutory maximum of \$6.5 (\$500,000 per count).
- **M&A: Remains a clear and present backdrop to gas case resolution:** Management has highlighted in its 10K that there is a risk that an adverse outcome in the pending federal criminal case related to the San Bruno explosion could require the company to separate its natural gas and electric utilities. With the CPUC President previously commenting on the potential need to address underlying perceived cultural and operational issues, we see this as a non-trivial element of the story, particularly given recent management turnover. If PCG decided it needed to pursue some type of financial restructuring, we believe that there would be interested counterparties, as evidenced by other potential transactions reported in the media (e.g., Oncor).

Based upon the original timetable the criminal case could end late July/early August but is difficult to predict.

While the Safety Culture OII is not an enforcement proceeding, the ultimate report to the CPUC could influence a decision to separate the businesses.

- **Diablo Canyon – Can PG&E get full recovery as requested?** As proposed the closure of the nuclear plant would not impact near-term earnings, albeit simply represents a short depreciable life on remaining rate base that would need to be replaced. A high capex budget is necessarily of offset quickly depreciating asset base. Further, full recovery on all items appears tricky with interveners. We emphasize the approval from the State Lands Commission to extend the operating license to 2025 from 2018 is a positive development. We perceive some, albeit low, degree of risk around earnings from the Diablo Canyon nuclear asset with \$2.0Bn of projected ratebase that management intends to recover/earn-on by its retirement in 2024/2025. [Further details on the Diablo Canyon announcement are available here.](#)
- **What do CPUC reforms bring? Not as concerning- and could be positive:** California Governor Brown recently announced reforms to the California Public Utilities Commission (CPUC) to improve oversight and transparency but the ultimate impact on the public electric utilities is hard to assess at this juncture. We see a clear desire by all parties to reduce risk (whether real or perceived) at the CPUC and allow it to return to focusing on the core issues. We see greater, more committed staffing levels with wider public confidence as a clear positive. See meeting [takeaways](#).
- **Ongoing settlement discussion in PG&E rate case bodes well:** The timeline for the 2017 GRC has been extended twice amidst ongoing settlement discussions. We emphasize this provides a potentially constructive backdrop to the story amidst our ongoing concerns of the pancaking of two substantial rate increases on consumers. We note the next update on the schedule is due in early August suggesting a further update (either delay for further settlement discussions or outright settlement). Resolution (particularly settlement) on its latest GRC rate case could meaningfully reduce the underlying risk profile.
- **DRP and the outlook for Demand Energy Resources:** We see the latest developments around developing a new structure to compensate utilities for ratebase and opening up investments to 'outside' parties could yet result in a reduction in the total capex opportunity in the state. We see Commissioner Florio's latest comments around this issue as concerning given the focus on ROE and suggestion there is some 'excess' return (which presumably could be culled from authorized ROEs at a later point). Bottom line, the \$450 Mn in DRP spend reflected in the outlook remains a principle source of risk to budget; we expect EIX to provide a wider range than usual around its own efforts given this uncertainty.

The wider backdrop remains limiting rate shock considerations amidst the series of increases imposed on consumers. For instance, we see some risk to the Diablo Canyon case as retirement costs (case would be resolved by year-end 2017) appear to be costly for ratepayers.

Can a reasonable settlement be found, with a more limited consumer bill impact. We suspect rate moderation and gradual increase in rates remains the key to the multi-year rate case outlook.

EPS Estimates slightly trimmed

Our EPS estimates have been trimmed for the latest capex disallowance but we have not changed our associated equity issuance assumption at this time. 2016E guidance includes \$600-\$800Mn of equity issuance assumptions but this could be impacted by this 2011-2014 disallowed capital (~\$700Mn), record keeping fine (<\$100Mn incremental), and ultimate San Bruno penalty treatment.

We continue to expect ~\$0.40 of annualized unrecovered GT&S revenue to be retroactively recognized in 2016 once a final decision is received (expected by October 2016) once the first phase decision is reached (revenue requirements).

Further charges for disallowed capital have a 30% 'multiplier' for further equity issuances based on guidance.

Figure 170: PCG Sum-of-the-Parts Valuation

PCG EPS Estimate Summary	2014A	2015A	2016E	2017E	2018E	2019E
EPS Estimates	\$3.50	\$3.12	\$3.70	\$3.59	\$3.76	\$3.96
Prior UBSe	\$3.50	\$3.12	\$3.74	\$3.64	\$3.79	\$3.99
Consensus	\$3.50	\$3.12	\$3.72	\$3.68	\$3.86	\$4.07
Guidance	-	-	3.65-3.85	-	-	-

Source: Company Filings, FactSet, and UBS Estimates

Valuation: Increase Price Target to \$67 from \$63

Our price target remains based on a 2018E P/E and the \$4 increase in our price target is driven almost entirely by the expansion of the utilities P/E peer multiple to 17.8x from 16.7x. PCG is currently trading at a ~3% discount to regulated peers, at the low-end of its 5-13% discount range over the past three years. Investors continue to gravitate to the name when the discount has touched 10% as it screens 'cheap' but we still believe the discount is deserved to account for regulatory uncertainties as noted above. We attribute the latest outperformance since mid-May at least in part to the [macro trade where investors have rotated into utilities](#) with large cap names trading at discounts such as PG&E benefitting.

We struggle to see PCG sustainably trading at any meaningful premium over the horizon, particularly given the challenging regulatory climate.

Figure 171: PCG Sum-of-the-Parts Valuation

PG&E Corp Valuation	UBS	Low Case	Base Case	Upside Case
Ongoing EPS - 2018E	\$3.77	\$3.77	\$3.77	\$3.77
Group P/E	16.8x	17.8x	18.8x	18.8x
(Discount)/Premium	(5.0%)	0.0%	5.0%	5.0%
Valuation Scenarios	\$60.00	\$67.00	\$75.00	\$75.00
Upside/(Downside)	-7%	4%	16%	16%

Source: Company Filings, FactSet, and UBS Estimates

In contrast we apply 1x-turn premiums to Edison International (SCE) and Sempra (SDG&E and SoCal Gas) which are growing the utilities without public equity and have fewer regulatory overhangs.

An important distinction between PCG and peers is that the PCG's equity dampens the translation from above-average ratebase growth to EPS growth.

Pinnacle West

We expect weather-driven expectations are largely too optimistic due to recent headlines around June heat wave and/or lower O&M expense, which could negatively impact the quarter in the 5-10 ¢ range versus expectations. However, recent shift to heat-wave in June-July could support the most important 3Q results and reduces risk to guidance. Expected decision in UNS rate case for July could provide read-throughs to PNW's [July 1 filed rate case](#), and we look to [value of solar docket](#) to provide potential framework for proper solar remuneration – which could affect the outcome of PNW's sweeping changes proposed in the rate case. Overall, uncertainty heading into the election season and three vacancies on the ACC suggest increased possibility of an outlier outcome for APS's rate case.

- **Key Drivers:** Relatively steady positive impacts from transmission cost adjustment, LCFR, and sales growth continue in the quarter although AZ sun benefit is set to roll of next Q since the program was largely finished 3Q'15. Although uncertain, we think plant outages will likely have an outsized effect on the quarter. This drives O&M impact down from ~17 cents in Q1 to our est of 9 cents, offset by a number of minor items.
- **Wildcard Factors:** (1) Despite extreme weather in June, April/May appear anecdotally to be more mild vs historic average, which could offset benefit in June. (2) Planned plant outages at Four Corners (Unit 4 and 5) and Palo Verde nuclear station continued from Q1 into Q2 but we expect maintenance was largely completed in time for summer - mid/early May, but shifts on timing could have a significant impact on O&M expense. Consensus is baking in either higher weather benefit or lower plant outage O&M expense, which seems too optimistic in our view.

Figure 172: PNW 2Q'16E Earnings Walk

2Q15A EPS	EPS
Reported 2Q15 Adj. EPS	\$1.10
Normal Weather	\$0.03
Normalized 2Q15 Adj. EPS	\$1.13
Weather vs. Norm	\$0.01
Transmission TCA	\$0.02
LCFR	\$0.02
kWh Sales	\$0.01
AZ Sun	\$0.01
O&M	(\$0.09)
D&A	\$0.01
Other, net	\$0.01
Dilution	(\$0.00)
UBSe 2Q16 Adj. EPS	\$1.13
Consensus	\$1.21
2016 Guidance	\$3.90-\$4.10
UBSe 2016	\$4.05
Consensus 2016	\$3.99

Source: Company Filings, Factset, UBSe

What are the Key Issues to Watch at PNW?

- **Data points on the Company's First Rate Case in 5 years:** While we would not expect concrete progress towards a settlement before intervenor testimony, schedule expected late July should provide clarity around timeline, while UNS decision is expected to provide some read-throughs to overall outcome and most importantly, PNW's controversial overhaul of residential rate design. We expect shift to reduced variable bill component and potential demand charge will prove particularly contentious with the pro-solar crowd and could maintain a relatively contentious relationship between camps going into an uncertain election season.
- **No Compromise with National Solar – Now What?** Previously discussed compromise with SCTY/RUN appears to be largely off the table now, as we expect PNW was more concerned with bringing local installers on board with the plan. Recent indications suggest some small businesses are shifting resources away from solar and more towards HVAC or energy efficiency businesses, using the utility as a potential partner instead – this will make it marginally more difficult for solar advocates to galvanize anti-APS sentiment.
- **ACC Election is Key – More Uncertain than Usual:** The terms of three ACC Commissioners terminate in January 2017, and if two Democrat candidates were to be elected, we could see more support for pro-solar policies, which could shift decisions in the rate cases or value of solar docket. For example, former ACC Commissioner Bill Mundell (1999-2008 (R)) is running for re-election as a Democrat on a campaign that's been publicly critical of APS. This remains one of the largest uncertainties into the back half of the year.

ACC primaries could have significant implications

The ACC primary election cycle will be key to watch in our view. The three seats up for election (or re-election) – while not explicitly deciding on any solar policies per se – could prove influential in upcoming rate cases. So far, two Democratic candidates – Bill Mundell and Tom Chabin – have signalled their intentions to run. On the Republican side, five candidates – Boyd Dunn, Robert Burns, Al Melvin, Rick Gray, and Andy Tobin – have announced their intentions to run.

In mainly red-state Arizona, the outcome of this election could be polarizing.

Value of Solar Case Could Set the Tone

The Arizona Value of Solar (Docket E-00000J-14-0023) general docket has started with hearings in April/early-May and could be decided on an accelerated timeline (3Q) potentially providing important read-throughs for PNW's rate case. The outcome of the case will likely set the tone for solar-customer compensation: low value would support reducing net metering rate or increasing fixed charges to levels closer to those that PNW has previously asked for, but initial evidence is thin and a decision to the contrary (high value finding) would likely further intensify the solar debate in Arizona. Given recent ACC staff opinions in other dockets, we see a constructive outcome read-through for PNW as the more likely scenario, although we note the outcome of elections could shift opinions and outcomes materially.

- **History:** Last year regulators voted 4-1 (then-Chairman Bitter-Smith dissenting) to move forward with a combined generic docket to consider both cost of service and the value of solar ahead of the APS rate case. The docket considers

PNW management stated that the outcome from the generic solar docket could change the compensation level for net metering included in its rate case.

topics including methodologies for determining the cost to serve customers with solar and the value of solar. This follows APS' withdrawal of a request to increase the interim \$20/mo fixed charge for solar customers and the company's recommendation to discuss the issues generically in the near-term in order to speed up the rate case proceeding next year.

How high will the demand charge be raised? Under the current solar tariff, customers pay roughly \$5/mo for an average system (assuming 7kW * \$0.70/kW). With the previous proposal in the state having been closer to \$20/mo, we think a compromise is likely to be struck closer to the higher figure (albeit still below). Following the federal ITC extension, we envisage lessened concern over the impact of higher fixed tariffs. The thought process in the initial \$5/mo rate appears to have been tied to an 'incremental' approach, effectively reducing subsidies to the industry gradually.

Looking at the First Cut of the Rate Structure

We enclose below the three pieces of the proposed rate structure. It would appear that solar constituencies are keen to see more of a fixed charge rather than demand charges to blunt the impact of higher consuming households. We continue to see rate design as the critical element of the rate case rather than rate recovery, albeit see potential for an alignment of interests between solar constituencies and other interest groups advocating for energy efficiency including AARP among others desiring less fixed/demand charges overall. *We include the initial proposal from APS below; we see this as simply a proposal, with clear potential for significant evolution.*

Figure 173: APS Solar Customer Rate Proposal

Solar Customer Rate Details (R-3)				
Section of Bill		Charge	Calculation	
1 - Fixed	Basic Service Charge	\$0.789	Daily	
			Summer	Winter
2 - Demand	On Peak Demand (\$/kW)	\$16.40	\$11.50	
3 - Energy	On Peak Energy (\$/kWh)	\$0.09090	\$0.06670	
	Off Peak Energy (\$/kWh)	\$0.05475	\$0.05475	

Source: APS Rate Case Filing, UBS

Solar Rate is Clearly Designed to Minimize Offset

As shown in the summary below, R-3 is clearly biased towards demand charges and basic service charges, with the lowest energy charges by far. Since a solar system will be unable to affect the fixed or demand portion of the bill (since demand is likely set in the evening for a typical customer), this will make the lost energy revenue for PNW much less than other options (from behind the meter generation – lower demand).

Figure 174: R-3 (Solar Tariff) has the lowest energy charge and the highest Demand Charge

Solar Customer Rate Details (R-3)				Rate R-1		Rate R-2	
Section of Bill		Charge	Calculation	Charge	Calculation	Charge	Calculation
1 - Fixed	Basic Service Charge	\$0.789	Daily	\$0.789	Daily	\$0.477	Daily
		Summer	Winter	Summer	Winter	Summer	Winter
2 - Demand	On Peak Demand (\$/kW)	\$16.40	\$11.50	\$6.60	\$6.60	\$8.40	\$8.40
3 - Energy	On Peak Energy (\$/kWh)	\$0.09090	\$0.06670	\$0.15160	\$0.12730	\$0.15160	\$0.12730
	Off Peak Energy (\$/kWh)	\$0.05475	\$0.05475	\$0.08070	\$0.08070	\$0.08080	\$0.08080

Source: Company Filings

EPS Estimates

We are adjusting our estimates down by a nickle to account for continued O&M expense at Palo Verde and Four Corners plants.

Figure 175: PNW EPS Estimates

UBS Estimates (\$/share)	2014A	2015A	2016E	2017E	2018E	2019E	2020E
UBSe EPS	\$3.58	\$3.92	\$4.00	\$4.16	\$4.52	\$4.63	\$4.71
Guidance			\$3.90-4.10				
Previous Ests			\$4.05	\$4.19	\$4.54	\$4.65	\$4.74
Consensus			\$3.99	\$4.20	\$4.42	\$4.56	

Source: Company Filings, Factset, UBSe

Valuation: Increasing PT from \$74 to \$80

We raise our PT from \$74 to \$80 based on ~1.5GX multiple expansion for the peer group. We emphasize risk to the multiple largely hinges on continued uncertainty on the rate case as well as lack of clarity around elections.

Figure 176: PNW Price Target

Pinnacle West Valuation: P/E Derived on 2018EPS					
Valuation		Price Target		Valuation	
2018EPS	\$4.52	2018EPS	\$4.52	2018EPS	\$4.52
P/E Multiple	17.8x	P/E Multiple	17.8x	P/E Multiple	17.8x
Premium/(Disc.)	-10%	Premium	0%	Premium	5%
Value	\$72.00	Value	\$80.00	Value	\$84.00

Source: Company Filings, UBSe

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

[6/7/16: The Sun Rises in the West](#)

[5/4/16: Taking the High Road on Solar](#)

[1/22/16: Gearing up to Make Their Case](#)

[1/7/16: West Waiting for a Better 2H16](#)

[11/2/15: Shifting towards the Rate Case Cycle](#)

[10/30/15: Hot Summer Meets Expectations](#)

[10/26/15: Catching Some Shade](#)

[9/17/15: Charting Its Own Course](#)

[7/31/15: Holding the Line on Costs](#)

[6/18/15: Sunrise after the Slide](#)

Portland General Electric

Key questions remain focused around ultimate outcome for the Carty plant and whether POR's next renewables RFP (towards the ~50% by 2040 standard) can yield a fourth-in-a-row win for the company. Management's contingency plan in the event Carty is delayed appears solid and we continue to see value accrual from the recently passed renewables mandate in the state. Shift in tax policy could add some complications to the ~2018 target for a build-and-transfer timeline for new wind; we note a more challenging start to the RFP process given the effort for an expedited effort (before year-end 2016 to qualify for 100% PTC) as also garnering some doubts. Regardless, this remains more of a timing issue and see a compelling reason for the commission to adopt an expedited framework to make use of the mutually beneficial 100% PTC (qualifies at 80% PTC beginning in 2017).

We forecast 2Q'16 EPS of \$0.46 vs \$0.44 last year and \$0.44 consensus.

Largely quiet quarter with a slight beat should be driven by reduced weather impact and steady growth on sales and ratebase. We believe tax rate shift YoY if wind was favorable could provide a further bump.

- **Key Drivers:** ~\$200M ratebase growth this year offset by commensurate opex and D&A growth should continue forward from Q1 while ~1% sales growth and somewhat reduced (but still negative) weather impact should improve the quarter somewhat. Incremental AFUDC impact is minimal now but July 31 Carty decision remains the biggest impact to look for next quarter.
- **Wildcard:** (1) 30% tax rate largely due to variances in wind production (less wind = less tax offset) could shift down to a more normalized 20-25% in the quarter, particularly if wind production turns out to be better than expected (1) PCAM adjustment could be less of an offset vs last year's relatively minimal ~\$400K positive, versus ~\$1M above the baseline in 1Q.

Figure 177: POR 2Q16E Earnings Walk

POR Earnings Walk	
POR 2Q15A EPS	0.44
Weather Effect	0.07
Weather Normalized 2Q15A EPS	0.51
Weather 2Q16	(0.05)
Weather norm sales growth @ 1.0% projection for 2016	0.04
Decline in supplemental tariffs	(0.02)
PCAM vs Baseline	-
Ratebase Growth	0.03
O&M and G&A	(0.04)
D&A	(0.03)
AFUDC	0.01
Interest Benefit	0.01
Income Taxes (20%-25% for 2016 vs 30% in 2Q15)	0.05
Other	-
Dilution	(0.04)
2Q16 EPS	0.46
2Q16 Consensus	\$0.44
2016 EPS	2.05-2.20
2016 UBSe	\$2.19
2016 consensus	\$2.11

Source: Company Filings, Factset, and UBSe

What to Watch for at POR

Stock sets up well into August as investor doubts run rampant on plant startup

We think the stock sets up well despite heightened investor concerns on shares into a 7/31 startup deadline for the Carty CCGT gas plant. We emphasize investor expectations already know of cost overruns in shifting E&C provider mid-construction and risk of (small) delay in timeline vs. mandated July end deadline. While mgmt recently reiterated confidence it could still achieve this target, even a small delay would be perceived positively. We perceive an inflection nearing as risks abate on timeline – and answers on recovery strategy are more fully fleshed out.

Bottom line, we perceive the Street as relatively focused on near-term risks on Carty – and see a clear positive skew to the story around any resolution. We think successful execution 'on time' would be perceived particularly well despite recent affirmations from management they remain on pace (albeit behind vs. initial schedule) to meet the final deadline of July 31st.

Carty First Fire on June 23. Capex on Track?

We note recent first fire on June 23 indicates the company continues to make progress on the 440MW natural gas base load Carty Generation Station, but is it enough? Complications arising from work performed by Abeinza, the previous contractor, could make finishing on time and/or on budget challenging, but the implications for POR are substantial enough that the company has committed to

an 8-K update in the event the timeline changes. Recall management has guided to \$635-670M capex targets yet general rate case authorization includes \$514M of recovery, which is a ~0.02 EPS impact. Most importantly, the July 31 target in service date remains the key date to meet in order to keep Carty in the most recent ratecase. While we continue to believe the July 31 date is achievable, we caution the balance between time, quality, and cost of the plant remain delicate, and the company would need to execute seamlessly to meet the goal.

Could POR benefit from a new ratecase for Carty? We see merits to recovery

The company has suggested it will seek recovery of net excess costs, but uncertainty around the insurance claim could complicate matters in the near term. We think POR could argue convincingly for recovery of cost overruns in light of Abengoa's selection through a Oregon PUC-approved process; recall total plant capex est. at \$635-670M vs. authorized recovery of \$514M, but does not include potential ~\$145.6 pending insurance claims. While a credible case seeing the commission authorized recovery under same set of datapoints as POR (discounted projected had known risks both POR and OR PUC underwrote). The company's willingness to file a new rate case is likely mitigated in large part today by (1) ongoing litigation against insurance companies and (2) desire to maintain regulatory relationship at the PUC following prior effort to avoid consecutive rate asks. Bottom line, we see limited uncollectables, making this more of a matter of transient under-recovery than long-term impact on '18+ EPS ests.

What Happens if the Plant is Delayed?

We don't necessarily see a binary outcome as the only option

While achieving the goal is clearly option 1, delaying the project to 17 or going through a regular RFP remain on the table in the event that Carty is delayed beyond the July 1st target date. Further, we think the most likely option in the event of delay remains an attempt to amend the rate case terms to reflect a delayed in –service date without changing the cost structure or impacting customer prices. This would potentially be achieved if the company were to go beyond the target date by a relatively short amount of time – POR could attempt to work with the relevant customer groups and the Oregon PUC to get an extension. *To us this would appear to be the most likely option.* In the event this is rejected, the company would file a general rate case to recover the incremental costs associated with bringing Carty on-line. Management also would consider filing a deferred accounting application allowing them to defer costs between the period of when the plant goes in service and when they would be able to recover the costs at the customers' price.

Still Waiting for a Renewables RFP – Hashing out the Details

We continue to anticipate POR's request to the Oregon Public Utilities Commission (PUC) for approval of an all-source renewable RFP for up to 175MW of renewables, with accelerated process and timelines – which could be worth approximately \$1 billion according to management, assuming 33% capacity factor, \$2,000/kw cost, and 525MWs nameplate capacity.

Small timing-related risk. Previously, POR was arguing for expedited RFP processing in light of PTC eligibility through 2018 only, but start of construction guidance allowing 4 years of leeway (through 2020 in this case) could add complications to the argument if the PUC were to scrutinize closely. We believe many large

Awaiting feedback on the process form IPPs and other parties – as push for expedited schedule

contractors have already reserved turbines for PTC compliance this year so there could be risk to the argument that POR needs to expedite the process accordingly. POR downplays this specific concern on timing of the RFP as project would still need to be selected by year-end 2016, it's just a matter of asset in-service. There's a credible argument to suggest ratable increases rather than lumpy long-term procurement of wind around PTC expiration.

The question is whether POR can push forward with an expedited RFP as well as succeed in winning an arrangement under a build and transfer structure to wind the award. Other parties involved have existing 'merchant' wind that could yet participate into the RFP, making details on what exactly qualifies for the RFP all the more critical.

Can POR and Developers Agree on RFP?

We note POR's relatively slow pace of RFP submission is likely due in part to negotiations with developers and other interested parties who are pushing the language towards criteria less favourable to build and transfer only. POR has won the last three RFPs in a row and we expect other parties will use potential leverage at the commission (in light of Carty issues) to advocate for differing RFP frameworks and non-utility ownership of projects. On the other hand, POR would likely look to ratebase renewable projects and incorporate costs into customer prices when in-service data is reached. Historically, POR's renewable projects have raised customer prices 2-3%.

Pacificorp is ahead of Portland with its own RFP

In a perhaps bold move, POR's sister utility to the West is pursuing its own procurement of additional renewables *without* seeking commission approval first. We emphasize this willingness to move forward on procurement without earlier consent illustrates the cost effectiveness of projects under the PTC and bodes well for POR's comparable efforts. That said, Pacificorp was a first mover and seemingly has their pick of the most 'economic' sites in the state.

We see confidence in Renewable RFP timeline as Pacificorp leads the way

Although POR appears to be structuring the RFP to account for independent developer concerns and maintain a level playing field, we note the company maintains a good deal of flexibility in driving RFP design. PGE has won each of the last 3 RFPs and while Carty related issues may garner increased scrutiny around any ratebased power facilities, we think the renewable (likely wind) opportunity appears tilted in the company's favor at this stage. We expect an RFP to be launched in '16 could drive a project by year-end '18 via a build-and-transfer project. Further, Pacificorp is actually pursuing an RFP without first seeking commission approval, a sign of confidence cheap wind w/ PTCs will ultimately be deemed prudent irrespective of upfront review.

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

[7/12/16 Racing to the Finish Line](#)

[5/5/16 Putting New Wind in the Earnings Sail](#)

[3/24/16 Going to Court as Sureties Balk](#)

[3/18/16 Zoning in on Renewables](#)

[2/16/16 Legislative Opportunity Looms](#)

1/15/16 Putting the Carty before the Commission

EPS Estimates – Why We're Above Street

Below we present our latest EPS estimates. We emphasize our estimates continue to reflect a build of multiple assets not yet in mgmt's formal capex, explaining our above-Street forward estimates. We admit near-term downside to 2016/2017 estimates from a delay in the Carty plant but emphasize with Street focused on 2018 & 2019 for valuation purposes we see this largely as transitory; the bigger deal here is whether the ongoing Carty project would involve any unrecoverable disallowances over time (in our view unlikely and limited if so given ongoing surety claims already).

Figure 178: Portland General Electric Key Estimates

	2014A	2015A	2016E	2017E	2018E	2019E	2020E
UBS EPS estimates	\$2.18	\$2.04	\$2.19	\$2.40	\$2.60	\$2.76	\$2.87
UBSe CAGR off 2015 weath norm \$2.20							6.9%
Prior UBS EPS estimates			\$2.19	\$2.40	\$2.60	\$2.76	
Street Consensus EPS (FactSet)			\$2.11	\$2.37	\$2.48	\$2.66	
Management Guidance - EPS			2.05-2.20				
DPS	\$1.12	\$1.18	\$1.26	\$1.35	\$1.44	\$1.54	\$1.64
DPS Growth (quarterly, usually in 2Q)			\$0.020	\$0.0225	\$0.0225	\$0.025	\$0.025
Dividend Payout Ratio (UBSe)	51%	58%	57%	56%	55%	56%	57%
Management Guidance - Payout			50-70%				
DPS growth	2%	5%		7%	7%	7%	7%
Management Guidance - Dividend growth			5-7%				

Source: Company Filings, Factset, UBSe

Valuation: Update PT from \$46 to 49

We are rolling forward our valuation from \$46 to \$49 based on ~1.5x PE expansion in the peer group, with 1X premium. We continue to ascribe a 1x premium to a 2018E peer P/E to account for both smid-cap bias, less leverage (no holding company borrowings) as well as improved growth outlook vs. peers. We continue to see POR as among the most attractively priced smid-cap stocks.

Figure 179: POR Valuation

Business Segment	Valuation Metric	2018 EPS	Low Case		Base Case				High Case	
			Valuation Multiple	(\$ MM) Value	Base Valuation Multiple		(\$ MM) Value		Valuation (\$ MM) Multiple	Value
Portland General Electric Company	P/E	\$2.60	16.8x	\$44	Peer Multiple	Prem/(Disc) to Peer	Base Multiple	\$49	20.8x	\$54
					17.8x	1.0x	18.8x			

Source: Factset, UBSe

PPL Corporation

PPL has been the largest laggard among regulated utilities in 2016 (-10% underperformance) which is expected given its significant UK concentration. We believe the most significant challenge for investors right now is that investing in PPL inherently involves making a call on the GBP foreign exchange rate. We continue to believe that the story deserves to trade at a discount but we believe the sell-off is overdone but caution that investors will likely be slow to return to shares, particularly with the guidance at risk today.

We forecast 2Q16 adjusted EPS of **\$0.50** vs \$0.49 in 2Q15 and \$0.52 Consensus.

- **Key Drivers:** We expect the UK business to decline again in 2Q and as the RIIO-ED1 rate transition's YoY comparison finally starts to fade we expect growth in 2H16 relative to last year. We believe the PA and KY utilities still benefit from higher margins following their recent rate cases as well. The weather largely appears to be a non-factor YoY.
- **Wildcard Factors:** (1) Impact of any currency re-strikes; management stated in March that it did not expect any additional activity prior to the UK referendum but that could have changed; (2) Load trends where Kentucky has been particularly vulnerable to declining sales.

PPL's quarter appears a tad weak relative to Consensus but the real debate is around the long-term outlook for the UK business.

Figure 180: PPL 2Q16E Earnings Walk

PPL Corp 2Q16E Earnings Walk	EPS
2Q15A Adjusted EPS	\$0.49
U.K. Regulated (PPL UK)	(\$0.02)
Gross Margins: New RIIO-ED1 Rates began April 2015	0.01
O&M	0.02
Depreciation	(0.01)
Financing	(0.00)
Income Taxes & Other	(0.04)
Kentucky Regulated (LG&E and KU)	\$0.02
Gross Margins: New Rates Effective July 2015	0.04
O&M	(0.00)
Financing	(0.01)
Income Taxes & Other	(0.01)
Pennsylvania Regulated (PPL EU)	\$0.02
Gross Margins: New Rates Effective Jan 2016	0.03
O&M	0.01
Depreciation	(0.01)
Income Taxes & Other	(0.02)
Parent & Other	(\$0.01)
Corporate Restructuring, Taxes, & Other	(0.00)
Dilution	(0.01)
2Q16E Adjusted EPS	\$0.50
2Q16 Consensus	\$0.52
2016 UBSe EPS	\$2.32
2016 Consensus	\$2.34
2016 Guidance	2.25-2.45

Source: Company Filings, FactSet, and UBS Estimates

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

[6/24/16 How the UK 'Leave' Vote Impacts US Utilities](#)

[4/29/16 All Quiet On The Western Front](#)

[2/8/16 Enjoying the Regulated Life](#)

[2/4/16 Rolling to 2018 at 5-6%](#)

[10/30/15 Adding to the Momentum](#)

[9/17/15 Charting Its Own Course \[Upgrade to Buy\]](#)

[8/17/15 Growing Like Blue Grass](#)

[7/1/15 Peering Across the Pond: Ofgem's RIIO \[Transcript w. Ofgem\]](#)

[6/8/15 Utilities Stand Alone](#)

What are the key updates for PPL?

- **How can PPL manage the UK headwind?** We believe the most significant challenge for investors right now is that investing in PPL inherently involves making a call on the GBP foreign exchange rate. We utilize ~1.32 in our estimates and valuation and the UBS forecast predicts 1.29/1.20 for YE16/YE17. Management has highlighted that if there is an increase in inflation that would be a positive for revenue but the net impact of the lower exchange rate overwhelms.

Management has emphasized that it does not expect an operational impact as a result of the UK referendum but that does not change the fact that earnings translated to USD from the segment will be significantly lower based on the latest GBP/USD exchange rate. Although PPL benefits from above-market hedges today, investors are focused on the 2019E impact when the book is substantially open.

The latest from our Economics team are available below:

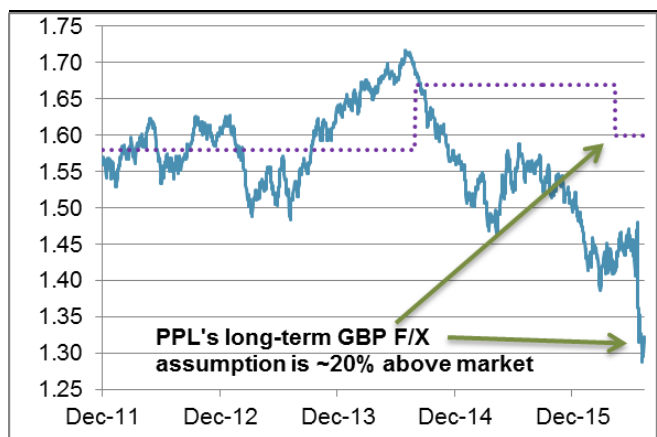
[7/6/16 Global FX Atlas: Which views remain after Leave?](#)

[6/29/16 UK: Overwhelmed by Uncertainty \[GBP Forecasts\]](#)

- **What is the dividend power now?** The current \$300-\$500Mn USD annual dividend guidance was based on a 1.60 GBP exchange rate and at a 1.30 exchange rate the new dividend range is closer to \$240- \$400Mn. While the impact on the dividend is relatively minor in the scheme of the \$1Bn annual dividend payments, we see the reduced dividend power as directly impacting the valuation for the segment. Management previously said the top-end of its repatriation guidance was unsustainable given its tax situation while the midpoint or lower was sustainable.
- **Will PPL adjust its heading methodology?** Ahead of the UK vote management layered in additional F/X hedges and has been diligent in the past to reduce currency volatility but investors are largely looking-through the hedge value today. The question is whether PPL will try to establish a new lower hedge baseline or focus less on this area with investors seemingly not giving credit.

Management has previously discussed hosting an Analyst Day following the UK referendum but is now waiting until it sees some stability in the foreign exchange market.

Figure 181: USD/GBP F/X Rate



Source: FactSet

Figure 182: PPL Hedging Profile

FX Hedging			Decrease in Rate		
Year	Hedged %	FX Rate			
2015	100%	1.57	2015	(\$0.05)	(\$0.10)
2016	93%	1.54	2016	\$0.00	\$0.00
2017	89%	1.58	2017	(\$0.01)	(\$0.02)
2018	41%	1.56	2018	(\$0.03)	(\$0.06)

Although PPL benefits from above-market hedges today, investors are focused on the 2019E impact when the book is substantially open.

Source: Company Filings

- **Quiet on the home front:** There is little new to report on the domestic front with management's capex review still ongoing as part of the business planning cycle to explore areas to accelerate deployment of bonus depreciation tax savings. PPL highlighted opportunities across the board - gas, solar, and T&D spending acceleration. Perhaps most interestingly was the discussion of gas growth in Kentucky as management has not historically focused there. We would not be surprised to see management ultimately explore gas reserves in ratebase in Kentucky, particularly if it does add more gas capacity at the electric utility. Based on recent datapoints in other states (Florida and Colorado) we believe regulatory approval will be challenging but this is likely a smaller piece of the story.
- **Compass review is going slower than expected but management is still optimistic:** The first segment of the Project Compass transmission proposal interconnects with Consolidated Edison's O&R service territory and ED is still reviewing the proposal as the transmission operator's technical review but the two companies are not joint venture partners. New York is still in the early steps of reviewing the technical aspects of PPL's proposal and the full process is expected to span all of 2016. Management has commented that the review process is progressing slower than expected but there have been no unforeseen challenges.

We look for an update later this year but it remains to be seen if management will attempt to push-up this update to help offset the lower earnings projections at the UK business.

PPL stated it was open to a JV partner on the ~\$500 Mn project (Phase I only) but it did not necessarily see any reason to bring in an outside player unless there was a strategic rationale.

Reducing EPS estimates for F/X mark-to-market

We present our latest EPS estimates below which reflect 1.32 GBP foreign exchange rate. Due to the presence of hedges the EPS impact is more material further in the future. The domestic growth story is still strong but using the current F/X assumptions we now estimate a -1.5% EPS CAGR for the UK which pulls down the US outlook. We still believe that Consensus estimates are too high

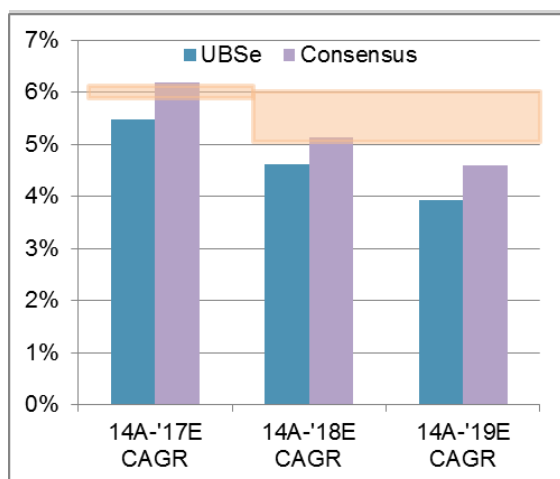
Figure 183: Updated PPL Earnings Estimates

PPL Standalone EPS (UBSe)	2014A	2015A	2016E	2017E	2018E	2019E	14A-'17E CAGR	14A-'18E CAGR	14A-'19E CAGR
UK Utilities	1.37	1.44	1.40	1.39	1.32	1.27	0.4%	-0.9%	-1.5%
PA Electric Utility	0.40	0.37	0.46	0.52	0.60	0.66	9.3%	10.5%	10.5%
Kentucky Utilities	0.47	0.51	0.56	0.59	0.62	0.63	8.0%	7.1%	6.1%
Retained Supply Corp. & Other	(0.21)	(0.12)	(0.10)	(0.12)	(0.11)	(0.10)			
Total	2.03	2.21	2.31	2.38	2.43	2.46	5.5%	4.6%	3.9%
Prior UBSe	2.03	2.21	2.34	2.43	2.55	2.63			
Consensus (7/13/16)	2.03	2.21	2.34	2.43	2.48	2.54	6.2%	5.1%	4.6%
Guidance	2.03	2.15-2.25	2.25-2.45	2.42	2.52		6.0%	5.6% (5-6%)	
FFO (CFO pre-W/C) / Total Debt		14%	16%	16%	15%	13%			

Source: Company Filings, FactSet, and UBS Estimates

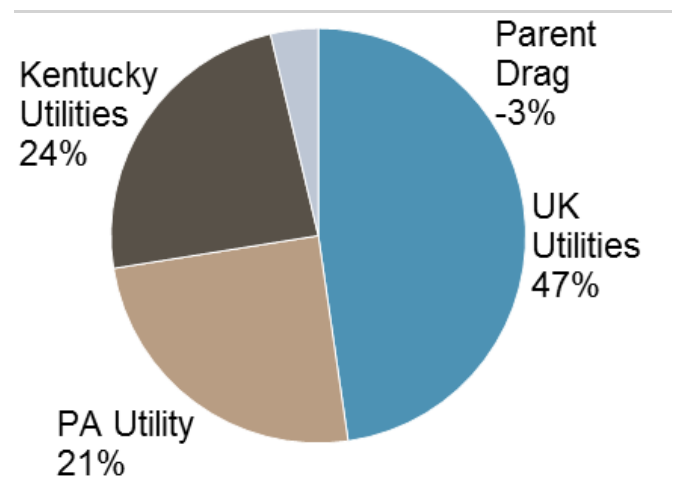
On the 4Q15 call (1.46 GBP on February 4th) management stated that if there was no improvement in the exchange rate, no restrikes exercised (as mentioned, restrikes have occurred), and no further incremental O&M savings then the EPS CAGR through 2018E would be in the bottom-half of the 5-6% range. As we indicate, we no longer see either the 2014-2017 6% EPS CAGR or the 2014-2018 5-6% EPS CAGRs as achievable.

Figure 184: Comparison of EPS CAGRs (UBSe vs Consensus vs Guidance)



Source: Company Filings and UBS Estimates. Pink bars indicate management guidance

Figure 185: 2019E EPS Breakdown



Source: Company Filings and UBS Estimates

Valuation: Maintain Price Target

Our valuation is based on a 2018E sum-of-the-parts. We have historically valued the UK at a ~1.0x-turn discount due to its below-average cash flows, flat EPS profile, foreign currency risks, and leverage. Following the UK referendum using the latest foreign exchange rate we now predict a declining EPS profile versus flat/slightly positive. As a result we have increased the discount to 3.0x.

We summarize the changes below:

- Increase in regulated utilities peer multiple to ~18.2x from 16.3x: **+\$5/sh**
- Reduction in UK EPS estimates: **-\$2/sh**
- Expansion of UK P/E discount to -3x from -1x: **-\$3/sh**

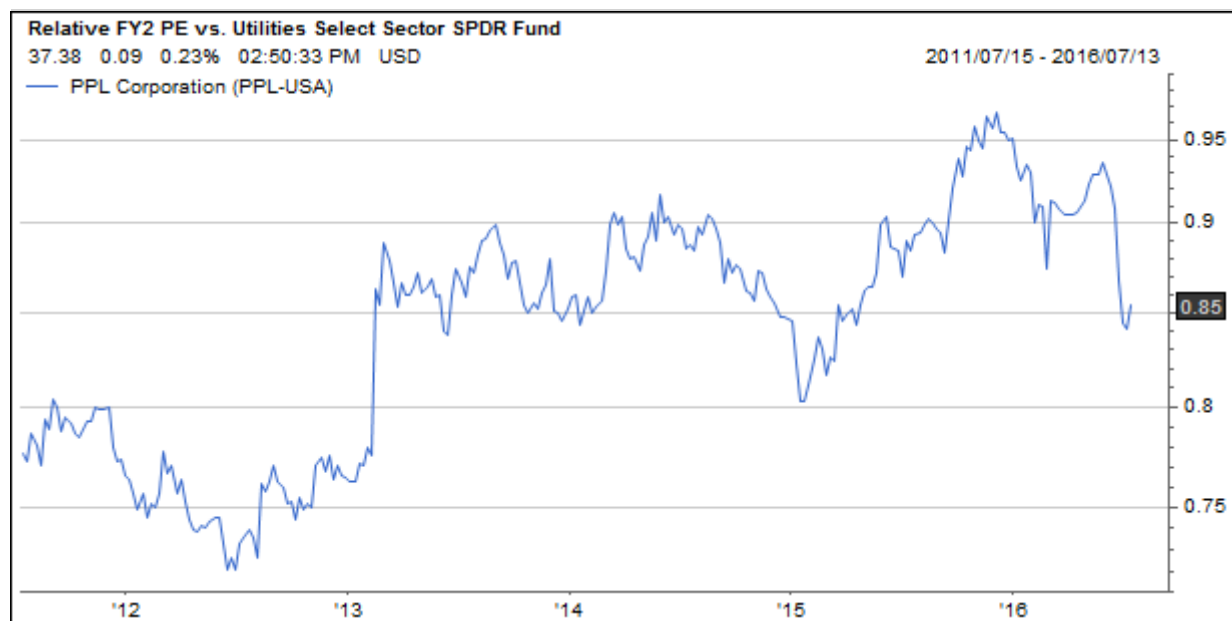
Figure 186: PPL Sum-of-the-Parts Valuation

PPL Sum-of-the-Parts (UBSe)	2018E	P/E Multiples					Enterprise Value		
		Prem/							
	P/E	Low	Peer	Disc.	Base	High	Low	Base	High
International (UK) Utilities	\$1.37	13.5x	18.2x	-3.0x	15.2x	17.2x	\$12,600	\$14,239	\$16,113
UK Hedge Value	-\$0.05	13.5x	18.2x	-3.0x	15.2x	17.2x	-\$446	-\$504	-\$571
Domestic Regulated Utilities									
PPL Electric Utilities (PA T&D)	\$0.60	17.7x	18.2x	1.0x	19.2x	20.2x	\$7,208	\$7,819	\$8,226
PPL Kentucky (KU/LG&E)	\$0.62	16.7x	18.2x	0.0x	18.2x	19.2x	\$7,054	\$7,688	\$8,110
Parent Interest Expense Drag	-\$0.11	16.7x	18.2x	0.0x	18.2x	19.2x	(\$1,211)	(\$1,320)	(\$1,392)
PPL Equity Value							\$25,205	\$27,922	\$30,486
Shares Outstanding (2018E Mn)							682	682	682
Total PPL Equity Value Per Share	\$2.43	15.2x			16.8x	18.4x	\$37.00	\$41.00	\$45.00
Implied P/E							15.2x	16.8x	18.4x
Premium/(Discount) to Group							-3.0x	-1.4x	0.2x

Source: Company Filings, FactSet, and UBS Estimates

PPL's discount versus the XLU had been steadily declining in 2015 but began expanding again as concerns around the UK referendum grew before significantly falling after the vote.

Figure 187: PPL 2Yr Forward P/E Ratio



Source: FactSet

Public Service Enterprise Group

The top investor question that management will have to address is whether the weak eastern 2019/2020 PJM capacity auction results will persist. While concerns are wide-spread in the market, we believe that articulating why a path back to improvement for the load center will help restore confidence in the outlook.

We forecast 2Q16 adjusted EPS of **\$0.58** vs \$0.57 in 2Q15 and \$0.62 Consensus.

- **Key Drivers:** Continued investment into the regulated side of the business, primarily transmission, forms the core growth in the quarter but again this is offset by weaker earnings
- **Wildcard Factors:** (1) Realized energy margin performance; (2) O&M control to offset mild 1Q16 weather; (3) cost of extended outage

Lower capacity revenue and an unfavorable power environment drive a negative 1Q outcome. Approximately half of the reduced FY16 Power earnings are expected to hit 1Q given the YoY capacity market trends.

Figure 188: PEG 2Q16E Earnings Walk

PSEG 2Q16 Earnings Walk		EPS
2Q15A Adjusted EPS		\$0.57
PSE&G YoY		\$0.05
Transmission Investments	Increase in Ratebase of ~\$1 Bn (tracking at +\$0.03-\$0.04 EPS YoY)	\$0.04
Distribution Investments	Increase in Ratebase of ~\$500Mn	\$0.01
Weather/Volume Impact	Unfavorable degree day comparison but weather norm. clause (WNC)	\$0.01
Renewables, CIP, & Other		\$0.01
O&M Growth	1-2% growth in O&M; offset by pension accounting change	\$0.00
D&A	Increase mostly offset by the transmission growth; \$27Mn bonus D @ T	(\$0.02)
Taxes and Other		\$0.00
Power YoY		(\$0.05)
Capacity Payments	~1.6GW less for 2015/2016 vs 2014/2015. Small impact for June-Dec	(\$0.01)
Hedges & Output Volume	~42TWh @ \$52 in '15 ~40TWh @ \$49 in '16	(\$0.05)
Weather/Volume Impact	Normalization. Erosion in spark spreads	(\$0.02)
O&M Growth	1-2% growth in O&M; pension. Might offset given the weather	\$0.05
Outages	Extended Salem 1 Outage: Lost Generation & Higher O&M	(\$0.02)
D&A	Organic increase in depreciation from spending; bonus D impact	\$0.00
Interest Expense	Slight benefit from Power Refinancing	\$0.01
LIPA Fuel Mgmt Contract	Services arrangement ~+\$0.01 YoY	\$0.00
Enterprise/Other YoY		\$0.01
2Q16E Adjusted EPS		\$0.58
2Q16 Consensus		\$0.62
2016 UBSe EPS		\$2.88
2016 Consensus		\$2.88
2016 Guidance		\$2.80-\$3.00

Source: Company Filings, FactSet, and UBS Estimates

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

[6/2/16 Underlining the Possibilities](#)

[3/16/16 Powering Up the Balance Sheet](#)

[2/22/16 Tracking New Jersey](#)

[12/22/15 Garden State Greenery](#)

[11/3/15 Furthering the Gas Prospects](#)

[8/6/15 Will Power Hold the "Keys" to the Future?](#)

What are the key updates for PEG?

- **Explicit carbon value coming in NJ - Not RGGI, but for nuclear:** Management continues to discuss with NJ regulators the value provided from its low-carbon nuclear footprint to the state and wider RGGI carbon targets. We see recent focus on nuclear contributions towards reaching local carbon targets as New York with leadership from Governor Cuomo had decided to effectively 'save' the states nuclear portfolio at an NPV cost of ~\$1Bn. While no specific proposals have come of parallel efforts in NJ and PA yet, we expect this could be a focal point of attention in 2H16. While NJ too has specific assets it is allowing to retire (Oyster Creek) principally due to once-through cooling impacts on estuarial waters. We look for developments and more specifics with 2Q to drive a bid to shares as investor sentiment remains exceptionally low following the latest PJM capacity auction.

While under Governor Christie, NJ actively took itself out of the RGGI regional carbon cap-and-trade program, we still perceive an interest in keeping in-state generation. By contrast, Governor Christie's energy focus has been to reduce energy bills through additional transmission to reduce constraints the area and maintain regional generation.

- **What to make of the PJM capacity auction outcome - End of the Premium?** It is unclear if the historic premium the company has garnered for a combination of PSEG/PS-North zones in the PJM footprint will prove evasive in future auctions, following its first auction without these benefits in 2019/2020. We expected continued pressures on this region from new contemplated plants, seeking to sell into either the wider EMAAC market or more focused PS market.
- **Why are investors so negative?** This focus remains principally on flat EPS through ~2020 as utility growth is offset by Power declines. This is not similar for the pressures facing other generation-related diversified utilities (FE, EXC, and ETR).
- **The loopflow issues provide boost to PS-North.** While management does not provide forecasts for capacity auctions as a matter of practice, it did highlight a potential -400MW tightening of the PS-North zone with the removal of the historic 'ConEd' loopflow (effectively bringing in upstate NY capacity and re-exporting it back to NYISO into New York City). Recent changes in how PJM tariffs for this flow make it uneconomic, and hence this appears to provide a -400MW improvement to net capacity imports into the region. The question is whether this import capacity will not be capitalized in some other form.
- **Eastern PJM will remain a premium load pocket.** Further, while not forecasting a specific price, it remains relatively confident the eastern MAAC load pocket will continue to price at a premium to the RTO region overall, seeing a sustainable advantage in the supply-load dynamic. We largely agree, seeing few new capacity projects contemplated for this region.
- **What is the Gross Margin from BGSS?** Normalized estimates of this business appear to be in the \$150-200 Mn outside of the premium Polar Vortex years in which PSE&G and Power benefitted from attractive FT arrangements for gas from the Marcellus. In recent years, margins appear to have been substantially (~\$200 Mn+) higher. We note recent years

A value uplift for PEG's nuclear units like Exelon could receive in New York would be a significant positive; however, PEG's nuclear assets appear more profitable.

(2014 and 2015) have been elevated but returned to more levels in the latest year, suggesting a return to more normalized levels.

Have BGSS, will travel.

- **Could the BGSS 'travel' with PSEG Power?** Yes. We emphasize management believe margins associated with its supply arrangement back with PSE&G on managing its firm gas needs would be sustainable even under an event of corporate separation of the two businesses. We had worried that such a move could prove an impediment (and driving timing) of mgmt's contemplated breakup of the two businesses down the line (which mgmt. has repeatedly remains a long-term prospect).
- **What other power markets are of interest? New York.** Management remains interested in other power markets, with a focus on New England and New York, other markets with capacity markets and regions in which PSEG already has an operating asset, the Bethlehem CCGT near Albany. Further, given its extensive knowledge of exporting and dealing with the New York grid from its Northern NJ footprint, expansion into this market would appear an ideal complement according to management. Conversely mgmt. is quite focused on avoiding expansion into existing markets where it has limited options given market power. We note there are several potential assets sales in New York, including TransCanada's well-marketed Ravenswood plant in NYC as well as ECP's Albany plant, Empire, which has been contemplated for sale previously as the fund reaches it maturity. We note management also has assets in New England, recently effectively replacing its Bridgeport Harbor station with a new gas plant.
- **But why is PSEG interested in generation expansion?** Investors continue to ask why mgmt. would expand its Power footprint amidst an explicit strategy designed to focus on regulated earnings. We see this as consistent, with the CCGT-oriented investments ultimately enabling a more diverse, more scale IPP, able to be spun out. We emphasize the core nuclear and gas assets in NJ would appear to represent limited diversity and substantial exposure to several single key factors. Moreover, management has been quite clear that any divestment effort would likely be executed as part of a Spin-Merge RMT structure, akin to PPL's 2015 spin of Talen Energy; this was designed to provide added diversity, limit the dis-synergies of breaking up the business, and be more tax efficient.
- **Utility updates**
 - **More transmission opportunities in NJ still:** Following years of above-average investment in transmission, management is quite confident the next round of PJM's Regional Transmission Expansion Planning (RTEP) process will yield yet another surplus of projects to boost long-dated capex. While specific capex upside is unclear, we remain confident PSEG will prove able to hit the upper end of its regulated growth ambitions.
 - **Where else is there potential upside on spend? Solar Filing:** PEG also flags potential upside on spend tied to its latest solar capex program of \$275Mn, which also has yet to be rolled into the plan. This is still quite modest, but consistent with the states' distributed energy ambitions. We continue to perceive interest in added grid resiliency and micro grid efforts as part of an effort to limit risks from storms such as Sandy.

- **Gas modernization continues beyond the scope of outlook:** While note formally upside, mgmt. reminds investors that there is an additional ~\$300 Mn/year in years 4 & 5 of the program.
- **Continued Dividend Growth despite risk of ~flattish EPS.** While potentially not always at a ~5% clip as the latest year, we emphasize our expectations for continued DPS growth of a healthy level. We believe DPS growth will largely be sized to address a stand-alone PSE&G utility entity without a cut after Power spin, while also providing sufficient latitude to continue to grow at a competitive rate for a utility (~mid-single digits).

EPS Estimates

Below we present our EPS estimates which are minimally changed following our recent PJM refresh.

Figure 189: Updated PSEG EPS Estimates

PEGEPS Estimates	2013A	2014A	2015E	2016E	2017E	2018E	2019E	2020E
PSEG Power	1.40	1.26	1.29	0.98	0.90	0.88	0.53	0.32
PSE&G	1.21	1.43	1.55	1.80	1.91	1.96	2.20	2.45
PSEG Enterprise & Other	(0.03)	0.07	0.07	0.09	0.09	0.10	0.08	0.06
Total	2.58	2.76	2.91	2.87	2.90	2.94	2.81	2.83
Prior	2.58	2.76	2.91	2.88	2.93	2.96	2.82	2.84
Consensus				2.88	2.90	2.95	2.95	3.12
% Regulated	47%	52%	53%	63%	66%	67%	78%	87%
Regulated EPS CAGR ('15-19')								8.0%
Guidance	\$2.80-\$3.00							

Source: Company Filings, FactSet, and UBS Estimates

Valuation: Increase Price Target \$1 to \$50

Our valuation is based on a 2018E sum-of-the-parts analysis where we apply an EV/EBITDA multiple to the Power subsidiary and P/E for the utilities. The +\$1/sh increase in our valuation is due to a slight peer group P/E expansion since our refresh which was most recent than for most pure-play regulated companies due to the recent PJM auction.

Figure 190: Sum-of-the-Parts Valuation

Sum of the Parts Analysis - Hedged Analysis - UBS							
All figures in USD millions except per share	2018E Adj. EBITDA	EV/EBITDA & P/E Multiple			Enterprise Value		
		Low	Base	High	Low	Base	High
PSEG Power	1,391	7.0x	8.0x	9.0x	9,737	11,128	12,519
Energy hedging normalization (adjust to open EBITDA)	(143)	7.0x	8.0x	9.0x	(1,003)	(1,146)	(1,289)
Capacity price normalization @ \$120/MW-day	(274)	7.0x	8.0x	9.0x	(1,918)	(2,192)	(2,466)
Half-year Keys & Sewaren CCGTs online in mid-2018 (discounted at 8% to '18)	86	7.0x	8.0x	9.0x	603	689	775
Bridgeport harbor CCGT online in 2019 (discounted at 8% to 2018)	58	7.0x	8.0x	9.0x	409	467	526
PSEG Enterprise /PSEG LI (LIPA)	57	5.0x	6.0x	7.0x	284	341	398
Total EV on adjusted open EBITDA					8,112	9,287	10,462
Add: NPV @ 8% 2018-2020 Energy Price Hedging						248	
Add: NPV @ 8% 2018-2020 PS Premium Capacity Pricing over \$160/MW-day						443	
Subtract: Net Debt						(3,414)	
NPV of Power and Non-Reg Equity					5,389	6,564	7,739
Number of Shares Outstanding (2018E)					508	508	508
Power & Holdings Equity Value per Share					\$10.61	\$12.92	\$15.23
	2018 Net Income	P/E Multiple					
PSE&G Net Income	997	16.8x	18.8x	19.8x	16,751	18,745	19,742
	Peer Multiple =	17.8x					
	Premium/Discount =	1.0x					
Number of Shares Outstanding (2018E)					508	508	508
PSE&G Equity Value Per Share					\$32.97	\$36.90	\$38.86
Total Equity Value per Share					\$44.00	\$50.00	\$54.00

Source: Company Filings, FactSet, and UBS Estimates

SCANA Corp.

Following our latest call with the SC PSC Office of Regulatory Staff and the latest disclosures about the VC Summer nuclear construction projects, we remain concerned about the construction timeline, particularly in light of the nuclear PTC eligibility. The availability of the fixed price option and continued regulatory support for the project are both positives but we think it is still pre-mature to believe that the story fully re-rates in 2016. That said, we still see the potential for a settlement with ORS and SCANA heading into the Fall hearings on the Fixed Price contract.

We forecast 2Q16 adjusted EPS of **\$0.67** vs \$0.69 in 2Q15 and \$0.71 Consensus.

- **Key Drivers:** Higher electric margin from the BLRA-related revenue for the VC Summer nuclear construction is the primary catalyst for earnings growth. There should again be a modest pick-up YoY from the 2015 depreciation study but this will likely be offset by higher financing costs for the quarter.
- **Wildcard Factors:** (1) O&M control following a challenging 1Q16 for both electric and gas; (2) sales volume trends with management still expecting slight erosion compared with positive trends. We believe that management remains conservative here.

Figure 191: SCG 2Q16E Earnings Walk

SCANA Corp. 2Q16 Earnings Walk	EPS
2Q15A Adjusted EPS	\$0.69
Weather vs Normal in 2Q15	(\$0.06)
Weather vs Normal in 2Q16	\$0.00
Other Electric Margin & Income	
Sales Growth (co guid -0.20% decline in 2016)	\$0.00
Base Load Review Act (BLRA)	\$0.05
Gas Margin	
E&G Gas Rate Stabilization Case	\$0.00
O&M Expense: 2% Growth in 2016	(\$0.01)
Other Taxes	(\$0.02)
Interest Expense, net of AFUDC	
Hybrid debt paydown from CGT proceeds	\$0.01
Issued \$500M debt in May 5.1%	(\$0.03)
Tax rates (32% for 2015 and 2016 vs 32% in 2014)	\$0.00
Depreciation	\$0.03
Dilution	(\$0.00)
2Q16E Adjusted EPS	\$0.67
2Q16 Consensus	\$0.71
2016 UBSe EPS	\$3.95
2016 Consensus	\$3.95
2016 Guidance	\$3.90-\$4.10

Source: Company Filings, FactSet, and UBS Estimates

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

[7/18/16 Expecting Some Slippage](#)

[5/2/16 Fixing the Summer by June](#)

[2/22/16 Considering the Options](#)

[11/4/15 Reducing Risk on all Fronts](#)

[8/20/15 Demand Growth Paints Paler Pic of Economy](#)

[8/5/15 Settling a Nuclear Deal](#)

[6/30/15 A Sweeter Summer](#)

What are the key updates for SCG?

- **Digging back into the VC Summer project math raises some flags:** We remain on the sidelines for the shares, but could see an opportunity to revisit once a firm schedule update is provided from Fluor to Westinghouse and SCANA. In the near term we see risk around the VC Summer schedule as Fluor fully vets its latest outlook. While the election of the fixed price option is pending before the PSC, the critical items to complement the further price increase on the project are both clarity on a fully vetted schedule from Fluor and execution of its hiring ramp. We expect clarity in the coming months, likely necessary prior to any final PSC election. This data point could prove a low for shares in ~2H16, with clarity on both the latest budget and schedule enabling another settlement on the fixed price deal.
- **Clarity will likely lead to a further delay in projects, driving near-term concerns:** Following the latest commentary in Georgia, we perceive similar concerns in South Carolina over further delays for the project, emphasizing productivity metrics would need to dramatically improve to achieve the current schedule (now trending 1.5-2.0x vs. slated initial project timeline). With 3 years left, this suggests real risk of a material delay notwithstanding substantial productivity improvements. Delay of the later Unit 3 could well put it at risk for collection of PTCs, an \$18/MWh benefit (for 8-year period). Bottom line, we see a clear bias for at least one of the units to miss this PTC eligibility date, with possible risk for both. Although with the benefit capped at \$125Mn/yr per site, this could offset some concern if just one unit didn't meet the deadline.
- **... But the big offset is nuclear PTCs could get an extension from IRS:** We believe the IRS could extend Production Tax Credits (PTCs) for the nuclear industry, currently slated to expire if not deemed in-service by the end of 2020. This would follow similar relief recently provided by the IRS for renewables, with 'start of construction' language clarification for eligibility. Several projects owners continue to advocate for this.
- **Ambiguity around what is "in-service" to qualify for PTC:** We perceive continued uncertainty on exactly what is required to meet the standard. This could be among the tweaks in the rules to enable an implicit extension.
- **Other key points on the nuclear construction:**
 - **Fluor needs to establish a vetted schedule.** This remains the key point, as all parties need clarity from Fluor as part of its full project re-evaluation since taking over. We think this is a gating item to getting approval of its fixed price option, from what we can tell (notwithstanding substantial caveats that would likely be embedded otherwise).
 - **Rehiring under way:** Fluor continues to ramp on hiring new staff to enable the schedule. This is not yet complete and is a major executional task in getting the project under way and a sense for the new schedule.
 - **Change orders are still pending:** Estimates of ~\$50 Mn pending change orders remains a further source of project scrutiny as execution on shifts in the plan remains uncompleted. SCANA appears confident that the uncertainty in the scope of these costs is modest.

With rate impact concerns critical to regulatory support of the project, we think receipt of PTCs is a key risk factor to project execution. Technically this item is a pass through to consumers to bring down the total costs and technically is not an earnings headwind per se, but its loss could meaningfully add to the pressure to accommodate a lower ROE as part of a settlement.

- **There are actually two schedules that matter:** *Integrated Resource Plan* vs. *Construction Payments Milestones*. Both schedules are to support a substantial completion date. Parties have indicated they could pursue dispute resolution on the later piece and would expect this to be part of a package before the commission *seemingly* before the final approval of the settlement in November. While such an election could happen as early as July 1, the subsequent resolution period would be 60-days.
- **Integrated Resource Plan is the key follow-up:** The last substantial update was in 2014 from Westinghouse and the prior consortium. The next will be the first with the new consortium with Fluor sub-contracting. While this may not be ready in time for the fixed price option, it would be integral to any subsequent review of the project costs.
- **Settlement is still possible on Fixed Price deal:** The testimony is slated for September 1st, and hearings would still likely take place on October 5. The further nuance this time is whether any settlement with the ORS would include agreements on an updated project schedule, given the risk stemming from the fact that the dispute resolution process has not necessarily started (and hence it is unclear if a schedule update will be made available by the late Summer).
- **Nascent worries emerging on project scrutiny and BLRA:** We note some recent concerns from interveners around further pushback on the project given project cost increases and potential for the Base Load Review Act (BLRA) to receive greater scrutiny at the State legislature. We would expect any potential changes in the BLRA in SC would likely be prospective only in order to mitigate the risk to the existing project, but even a more robust discussion on the BLRA at the legislature would sound a cautious note, in our view.

Maintain EPS Estimates

We have not yet reflected any possible benefit from higher nuclear capex and CWIP pending the final outcome of milestone planning with the consortium (and whether the company picks a fixed-cost option). We continue to see some incremental cost pressure to 2017 and 2018 EPS projections on the back of the delayed nuclear schedule and the stated intention to avoid electric rate cases during construction.

Figure 192: SCANA EPS Estimates

SCANA EPS by Segment	2014A	2015A	2016E	2017E	2018E
Carolinas	\$3.23	\$3.41	\$3.30	\$3.47	\$3.70
PSNC (Gas Utility)	\$0.39	\$0.41	\$0.44	\$0.49	\$0.50
Parent/ GA Retail	\$0.17	(\$0.01)	\$0.21	\$0.23	\$0.17
Consolidated	\$3.79	\$3.81	\$3.95	\$4.19	\$4.38
Consensus	\$3.79	\$3.81	\$3.95	\$4.15	\$4.44
2015 CAGRs					4.7%
Prior UBS Estimates	\$3.79	\$3.81	\$3.95	\$4.19	\$4.38
Growth Rate	11.9%	0.6%	3.6%	6.0%	4.5%
Mgmt Guidance	\$3.70-\$3.90	\$3.60-\$3.80	\$3.90-\$4.10		
Long-Term Guidance (3-6% Range)					
High	3.60	3.82	4.05	4.29	4.55
Med	3.55	3.71	3.88	4.05	4.24
Low	3.50	3.68	3.82	3.98	4.14

Source: Company Filings, FactSet, and UBS Estimates

Valuation: Maintain \$72 Price Target

We continue to value SCG on a SOTP basis, applying a discount to the 2018E peer utility P/E.

Figure 193: SCG Sum of the Parts on 2018E

SCANA Corp Valuation		UBS		Low Case		Peer Multiple	Base Case		High Case	
Business Segment	Valuation Metric	2018	Multiple	Valuation (\$s MM)	Value		Prem/ Discount	Valuation (\$s MM)	Value	Valuation (\$s MM)
Regulated Business										
SCE&G Franchised Electric	P/E	\$3.70	15.5x	\$8,255	17.7x	-7%	16.5x	\$8,789	17.5x	\$9,323
PSNC	P/E	\$0.50	17.7x	1,286	18.7x	0%	18.7x	1,359	19.7x	1,432
SCG Utilities Equity Value				\$9,542				\$10,148		\$10,755
Georgia Retail (Net of Corporate)	EV / EBITDA	\$47	4.0x	\$187			5.0x	\$234	6.0x	\$281
Total				\$187				\$234		\$281
Low & High Cases (See Below) in \$/sh Terms					(\$5.81)					\$3.72
SCG Equity Value				\$8,890				\$10,383		\$11,572
Fully Diluted Outstanding Shares (2018)				144				144		144
SCG Equity Value per Share				\$62.00				\$72.00		\$80.00
Low Case: Disallow ance on PTC Loss - Liquidated Damages										
Loss of Full Production Tax Credit @ 100% S/h impact (SCE&G Portion)					(1,400)					
Offset by Liquidated Damages					372					
Net Impact to Shareholders under Scenario					(1,028)					
Discount back 3-years from 2020 in-service					(839)					
\$/sh Impact					(\$5.81)					
High Case: Higher Costs Fully Recovered										
Current SCE&G Capex										7,601
Potential Increase (%)										10%
Higher Recoverable Capex										760
EPS Benefit										0.28
Value using Group P/E Multiple										\$4.55
Discount back 3-years from 2020 in-service										\$3.72

Source: Company Filings, FactSet, and UBS Estimates

Sempra Energy

Analyst Day yields no surprises as stays the course on 2020 12% EPS CAGR. While mgmt did not necessarily provide tangible new products at the Analyst Day, SRE provided the first framework in sizing balance sheet and continued to articulate primarily new areas of utility growth.

We forecast 2Q16 adjusted EPS of **\$0.94** vs \$1.03 in 2Q15 and \$0.98 Consensus.

- **Key Drivers:** Retroactive general rate case revenues for the utility subsidiaries but more than offset by comparative weakness versus the power & gas segment.
- **Wildcard Factors:** (1) Foreign currency impact; (2) ultimate level of gas segment drag YoY with higher development costs

Quarter looks a bit light but involves lumpy timing items that could skew the view.

Figure 194: SRE 2Q16E Earnings Walk

Sempra Energy 2Q16 Earnings Walk	EPS
2Q15A Adjusted EPS	\$1.03
SDG&E	\$0.02
SoCal Gas	\$0.02
Sempra International	
South America	\$0.00
Mexico	(\$0.02)
F/X Impact	(\$0.02)
US Power & Gas	
Renewables	(\$0.01)
Natural Gas	(\$0.08)
Parent	\$0.00
Dilution	(\$0.01)
2Q16E Adjusted EPS	\$0.94
2Q16 Consensus	\$0.98
2016 UBS _e EPS	\$4.80-\$5.20
2016 Consensus	\$4.79
2016 Guidance	\$4.98

Source: Company filings, FactSet, UBS estimates

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

[7/20/16 Setting Course in the Right Direction](#)

[4/1/16 Sticking to Their Guns](#)

[2/29/16 Pivoting Towards Best-in-Class Income Growth](#)

[11/5/15 Poised to Hoist Growth Again](#)

[9/15/15 Still Beating Best-In-Class Expectations](#)

[8/7/15 Exuding Confidence](#)

[7/6/15 Watching the Sparks and Sparklers \(page 8: "The Next Round of California Capex"\)](#)

[6/19/15 The Northern Opportunity](#)

What's our latest thinking on the story?

We continue to see a variety of levers on the SRE story after the Analyst Day. We see shares as well positioned *to continue to outperform peers*. While limited new firm project announcements were provided at the Analyst Day, the outlook remains intact, with a host of opportunities ranging from Mexican infrastructure to

LNG. Notwithstanding execution in Mexico and Midstream, we see even the base utilities as provided meaningful positive earnings revision potential.

Updated Estimates:

We include our updated estimates relative to mgmt's latest ranges. We do not reflect buybacks and hence modestly shift down our estimates.

Figure 195: Updated EPS Estimates moderates expectations relative to baseline plan – but so much upside still

Net Income	2014E	2015E	2016E	2017E	2018E	2019E	2020E
SoCalGas	\$332	\$419	\$433	\$408	\$441	\$468	\$493
<i>Guidance</i>							
SDG&E	\$528	\$572	\$573	\$594	\$640	\$676	\$710
<i>Guidance</i>							
South America	\$170	\$174	\$177	\$168	\$177	\$186	\$194
Sempra Mexico	\$192	\$213	\$226	\$259	\$292	\$324	\$354
Sempra International Total	\$362	\$387	\$403	\$427	\$469	\$510	\$547
<i>Guidance - Sempra International</i>							
US Gas	\$50	\$8	(\$55)	(\$56)	\$156	\$329	\$336
Renewables	\$40	\$55	\$51	\$69	\$74	\$79	\$80
US Gas & Power Total	\$90	\$63	(\$4)	\$13	\$230	\$408	\$415
<i>Guidance - US Gas & Power</i>							
Parent & Other	(\$130)	(\$133)	(\$195)	(\$190)	(\$201)	(\$219)	(\$248)
<i>Guidance - Parent & Other</i>							
Consolidated NI	\$1,182	\$1,308	\$1,209	\$1,252	\$1,579	\$1,843	\$1,917
<i>Guidance - Consolidated NI</i>							
UBSe EPS	\$4.72	\$5.21	\$4.79	\$4.92	\$6.16	\$7.14	\$7.38
Prior UBSe		\$5.21	\$5.00	\$5.20	\$6.25	\$7.20	
<i>Guidance - EPS</i>			\$4.80-\$5.20	\$4.60-\$5.00		\$7.00-\$7.50	\$7.20-\$7.80
<i>Consensus EPS</i>		\$5.21	\$4.82	\$5.22	\$6.13	\$7.17	

Source: Company report and UBS estimates

Estimates vs. Guidance Ranges: How we stack up relative to each biz?

We include our updated estimates relative to mgmt's latest ranges. We do not reflect buybacks and hence modestly shift down our estimates.

Figure 196: Updated Estimates relative to SRE Mgmt

2016 Analyst Day (July 2016) Base Plan Projections vs UBSe, 2016-2020									
Guidance:	SRE Guidance 2016	UBSe 2016	SRE Guidance 2017	UBSe 2017	UBSe 2018	UBSe 2019	SRE Guidance 2020 w/o Share Buyback	SRE Guidance 2020 with Share	UBSe 2020
SDG&E	\$550M-\$600M	\$573M	\$575M-\$625M	\$594M	\$640M	\$676M	\$660M-\$710M	\$660M-\$710M	\$710M
SoCalGas	\$380M-\$420M	\$433M	\$390M-\$430M	\$408M	\$441M	\$468M	\$465M-\$515M	\$465M-\$515M	\$493M
US Gas and Power	-\$15M to \$5M	-\$4M	\$5M-\$25M	\$13M	\$230M	\$408M	\$365M-\$445M	\$365M-\$445M	\$415M
International	\$380M-\$410M	\$403M	\$410M-\$440M	\$427M	\$469M	\$510M	\$520M-\$560M	\$520M-\$560M	\$547M
Parent & Other	-\$175M to -\$145M	-\$159M	-\$185M to -\$155M	-\$158M	-\$169M	-\$187M	-\$215M to -\$185M	-\$280M to -\$250M	-\$216M
Sempra Earnings	\$1,120M-\$1,290M	\$1,209M	\$1,195M-\$1,365M	\$1,252M	\$1,579M	\$1,843M	\$1,795M-\$2,045M	\$1,730M-\$1,980M	\$1,917M
Avg diluted shares	253	253	255	255	0	257	260	245	260
EPS (2016 Analyst Day Guidance)	\$4.60-\$5.00	\$4.79	\$4.80-\$5.20	\$4.92	\$6.16	\$7.14	\$6.90-\$7.50	\$7.20-\$7.80	\$7.38
Base Plan Adj. EPS w/o REX Sale	\$4.80-\$5.20		\$5.00-\$5.20				\$6.90-\$7.50	\$7.20-\$7.80	
Revised Guidance (May 2016)	\$4.60-\$5.00						\$7.20-\$7.80		
Prior UBSe EPS		\$5.00		\$5.20	\$6.25	\$7.20			\$7.47
Consensus EPS		\$4.82		\$5.19	\$6.14	\$7.17			\$7.40
EPS Growth Rate				2.7%	25.3%	15.9%			3.4%
UBSe CAGR 2016-2020 off the midpoint of 2016 revised guidance \$4.80									11.4%
DPS		\$3.04		\$3.30	\$3.58				
DPS Growth Rate				8.5%	8.5%				
Guidance		8-9%		8-9%	8-9%				

Source: Company report and UBS estimates

Valuation: Raising Target to \$123/sh from \$118

We include our updated summary SOP valuation. Our price target is higher principally on SDG&E and SoCal Gas estimates and MtM group multiple uplift. We are also tweaking our expectations on the renewable.

Figure 197: Comparison : Old vs. New Sum of the Parts

Summary Sempra Sum of the Parts Analysis - UBSe	Primary Methodology	Valuation/ Share	Prior Valuation/ Share
Segment			
Sempra Natural Gas			
Storage, Cameron (Import & Interstate), and REX	7-12x EV / EBITDA	\$2.21	\$2.22
Gas LDCs	19x P/E	\$1.07	\$1.03
Total Sempra Natural Gas		\$3.27	\$3.25
Sempra US Power & Renewables			
Solar	14.5x EV/EBITDA	\$2.81	\$3.23
Wind	8-15x EV/EBITDA	\$0.49	\$0.49
Accelerated Depreciation Tax Shield and Other	NPV	\$4.02	\$4.51
Total Sempra US Power & Renewables		\$7.32	\$8.23
Cameron LNG Export Project			
Trains 1-3	NPV of 10x EV /	\$20.26	\$20.38
Accretion due to GP/LP Structure in MLP	EBITDA	\$0.00	\$0.00
Train 4	discounted to	\$1.30	\$1.31
Total Cameron LNG Export Project		\$21.56	\$21.69
California Utilities			
SoCal Gas	20x P/E (No discount)	\$33.88	\$33.69
SDG&E	19x P/E (No discount)	\$46.69	\$42.51
Total California Utilities		\$80.58	\$76.20
International			
SRE Mexico/IE Nova	Public Value	\$16.43	\$14.84
Chile (Chilquita) - Unlisted	14x P/E	\$4.64	\$4.62
Peru - Listed	Public Value	\$4.95	\$4.65
Total International		\$26.02	\$24.11
Less: Parent Debt	Book Value	(\$15.45)	(\$15.54)
Grand Total Sempra		\$123.00	\$118.00

Source: Company reports and UBS estimates

What We Learned from The Recent Analyst Day

Setting Course in the Right Direction

Analyst Day yields no surprises as stays the course on 2020 12% EPS CAGR

Management articulated a consistent story in its articulation of 2020 prospects, leaving intact its 12% EPS CAGR through 2020E as well as its 8-9% DPS growth. Further, growth projects remained largely intact through the period, as expected, without any meaningful new announcements on project success. The Analyst Day largely reiterated the balance sheet flexibility afforded through its development of Cameron 1-3. We see the story continuing to shift towards Mexican development efforts to add confidence on incremental deployments w/o details on the lumpy Train 4 success.

Abundantly conservative view leaves ample growth, but how much?

Among the notable datapoints was 2020E combined net income of \$1.1-1.2Bn across the two utilities (UBSe was at the bottom end); while 2020 was unchanged from preview provided with 1Q results, the composition was better in our view. Further, we flag upside to not just gas infrastructure investments, but readily for the core utilities too. We highlight additional attrition revenue relief beyond the 3.5% embedded through 2018E in its latest rate case as well as in the Put option contract with Calpine

for Otay Mesa are just the latest levers. While Aliso is still pending, limited updates in 2H16 make this a relatively quiet part of the near-term investment case but is a lingering risk.

Continuing to Stress the Balance Sheet – defining the inherent latitude

The key to the SRE story remains finding superior investment alternatives to buybacks. 2020E FFO / Debt is ~21% pre- \$1.5Bn share repurchases and ~19% post-repurchases. Bottom line, there's more if need. Likely given the upsides that exist already, we see this extending the 12% growth further into the future. The real factor to keep this level of growth will be driven via LNG & other high ROE deployment opportunities vs. the ~7% 2020 earnings yield of a buyback today. A 12% ROE on physical investments would yield ~\$0.30 improvement vs. base scenario contemplated. Most importantly, mgmt is confident it is nearing key milestones on multiple project developments in 2H.

Segment Level Thoughts

We present initial segment level thoughts following the Analyst Day without adjusting our formal estimates and target for the latest disclosures.

Financial Updates

What's in the buyback figure? More than you think

Management notes that it would not buy back shares at \$100/sh+ where it is currently trading. Instead, mgmt assumes buybacks of ~20 Mn+ shares in the deployment of its buyback program (when adjusted for the repurchase of its DRIP and ESOP-related programs) albeit is not explicit in its plan. While the disclosure without buybacks indicated 260 Mn shares for 2020, the 2020 case with buybacks indicates approximately ~15 Mn shares less. While this is a cautious statement on its own equity value with a projection for capital depreciation, we interpret this as management simply being cautious on its own prospects with yields and utility valuations at record highs of late. We also read this hesitancy on share buybacks of its own stock as illustrating its own caution on pursuing wider utility M&A opportunities. Mgmt seemingly views utility valuations as too expensive to warrant exploring relative to other organic opportunities and other asset classes. *All this said, we note some uncertainty on how exactly the buyback was positioned among investors; we see this as a detail seeing the \$1.5 Bn earmark as the more relevant figure rather than judging the total of hypothetical shares repurchased.*

Digesting the FFO/Debt Figures: More Latitude Where it Came From

Management provided added granularity in its balance sheet metrics, indicating on an Adjusted Basis its FFO/Debt was at 21%, albeit using GAAP financials this figure was closer to ~23% on a projected basis. Recall the rating agencies require companies to maintain a 17% metric under its current risk profile approach, which is comparable to the adjusted figure of ~21%. Under the share repurchase avenue the company has deployed only ~half of its balance sheet latitude, driving metrics down to 19%. Should mgmt find additional opportunities we could yet see this reduced further, closer to the 17%. Lastly, we perceive optimism the FFO/Debt requirement itself could yet migrate down, as part of a wider sector trend. Bottom line, while investors have been cautious on shares in the last year that LNG expansions might not happen (among other growth doubts) – management clearly articulated that even assuming just share buybacks its 2020 EPS growth was achievable.

Don't expect upside to 2020 growth with project success – rather expect the growth rate to be extended

We look for management to extend out its ability to maintain its growth rate with success of forthcoming growth projects. While it continues to push forward on a variety of fronts, we believe mgmt would rather deploy its capital more accretively than share buybacks immediately, deferring this dry powder to a future period. Further, with a time delay on when equity capital is invested relative to when it bears fruit, we would not be surprised to see additional organic growth allow SRE to focus once more on extending beyond 2020 (rather than an immediate uplift in the current horizon)

Utilities pose more potential than we thought

Otay Mesa: What is this Worth?

We emphasize the ~\$280 Mn put strike price embedded in the option to Calpine suggests incremental EPS of ~\$0.06 (\$14 Mn), using its authorized 10.3% ROE. Given the strike price of the Put from Calpine at meaningfully above market prices (\$460/kW vs. ~\$100-200/kW for market), Calpine would be incentivized to elect the Option. From a regulatory perspective, the PPA as originally approved from the CPUC embedded the recognition this option was a real potential and hence has an implicit approval already. That said, with growth in solar continuing to eat into generation prospects we would not be surprised by subtle pushback given a lack of demand from the CPUC. As such, we see a corresponding potential to monetize other higher heat rate assets outside of the local RA load pocket to offset capacity additions. Such an asset could include Desert Star in NV, which is a SDG&E-owned 490 MW CCGT built in 2000. Despite recent low price points in the West, the asset is ideally situated near transmission for both LADWP and NV Energy.

This appears the most obvious of all 'upside' cases for the utilities

Kickstarting large transmission again via DC intertie

In an effort to ramp California utility spending, Sempra's latest long-term focus at SDG&E is a wider focus large-scale transmission including a HVDC transmission line directly into the core of its service territory from unconstrained adjacent regions.

Expecting backwardation in ROE at the utilities

Consistent with past updates, growth remains conservative vs. peers with ~7% and 9% ratebase growth respectively at SDG&E and SoCalGas, however only 4-5% EPS growth. While admittedly the impact of the repairs tax is a headwind and as is the potential ROE reset in at least a FERC case, assumed compression appears disproportionate.

What is the Electric Vehicle Opportunity? Quite large.

We agree with management that the most tangible opportunity for SDG&E is adapting to the distribution network needs around Electric Vehicle (EV) adoption. Mgmt stresses that with triple the density of any comparably sized city, San Diego would appear among the ideally situated urban areas to scale deployment. The key question remains whether the CPUC will continue to allow for a ratebase approach to scale charging stations in a pilot effort to encourage adoption; further, the question is whether the CPUC will allow for continued ratebasing of these assets, at least in more available areas amidst a scaling of the EPS.

Aliso Canyon – remains status quo

Mgmt continues to mitigate risks relating to the gas storage leak earlier this year. We view the asset as largely in limbo until the Blade Energy report is released in the ~1Q17 timeframe. We would expect the CPUC to open an Order Instituting Investigation (OII) at that point to more formally evaluate the events – and whether any fines would be due. We note that penalties remain undefined and would be unlikely addressed by insurance; that said, costs incurred thus far have largely been recoverable from insurance proceeds and spend on relocation costs, the bulk of this cost thus far has been stemmed. We don't expect significant developments on this front through the balance of the year.

Fewer Pipelines? CPUC Rejects Major North-South Pipeline

The CPUC recently rejected Sempra's latest effort to expand their pipeline network via a new \$623Mn pipeline (which was *not* included in the growth prospects in any event). As a follow up management sees opportunities to continue invest in LNG peak shaving facilities that would address gas needs for the constrained gas area impacted.

Emphasizing the Mobile Home opportunity.

Among the more novel opportunities that continue to be discussed by both utilities is service to mobile home parks across Southern California. While undefined in the capex and incremental customers for particularly gas, this would appear to provide a novel source of new customers.

Projections show ROE compression

While investors have been broadly concerned about a reduction in premium ROEs for some time, we note our ROEs embedded in our projections assume substantial compression already to 'normalized' levels.

International Updates:

Likely to issue equity at IENova than keep equity at Sempra

Despite fewer investment opportunities than would ideally be targeted, mgmt. remains clear it would rather raise equity at IENova than provide additional equity from the parent sponsor on incremental projects. While not specific on a funding commitment, it would appear mgmt. continues to view the relatively high multiple of IENova as the better risk adjusted idea. We largely agree as we see high valuation multiples in Mexico amidst a competitive backdrop as the riskiest element of the SRE story (Further LNG is a much more 'familiar' development risk – and largely excluded from Street expectations).

But Barriers to Entry in Mexico are Higher

On the other hand, actual transmission and gas project development competition may be more insulated because land acquisition and permitting rights in Mexico appear quite challenging. TransCanada, Fermaca, and Carso are the main competitors, while local developers often don't meet the specified financial criteria for large project bids. This is in contrast discrete project development (such as power plants) where a given land piece can be acquired comparatively easily – versus multiple miles worth of negotiations for transmission and gas lines. This helps explain why IENova was outbid by the likes of Enel and SunPower for the recent power auction. Further, unlevered (dollar denominated) returns for pipelines

are in the low double digit range versus some bids in the power auction that were in the 5-7% unlevered IRR range.

Transmission: more than meets the surface?

Mgmt sees a total of \$13.4Bn in transmission opportunities; this is relative to just \$2.6 Bn for instance in incremental power and renewable opportunities. We look for the first RFP this Fall with a HVDC 600km line in southern Mexico. We remain concerned about the level of competition for such development activities from a variety of parties. Nonetheless, given the magnitude of the opportunity we would not be surprised to see at least some wins awarded to IENova.

Marine Pipeline Project: Now Reflected in Baseline Outlook

We emphasize the Marine project is a key development for Sempra and IENova, with the JV providing an additional source of \$500 Mn of equity deployment for Sempra relative to the capital allocation case allocated with 2Q results. IENOVA's share of the project cost is \$825Mn. [Further details are available here \(P6\).](#)

Other Incremental Opportunities in Mexico, but Longer Term

Post 2018, main pipeline infrastructure should be largely built out in Mexico and there could be a number of opportunities with private companies or LDCs for smaller connecting infrastructure. IEnova is laying the groundwork to capitalize on this but we would not expect to see substantial project announcements in the near term on this front. On the renewables front, the next power auction later this year could favor the company more than the first auction which included more substantial (CFE funded) incentives that yielded lower power bids from players with existing land or partially developed projects. Future bids are likely to have lower incentives built in and position IEnova for potential project wins, but low returns thresholds from some competitors (~5% unlevered IRR) could leave the opportunity set somewhat limited.

Open to expansion in South America.

In contrast to peers, management was quite explicit in its willingness to explore additional utility acquisitions adjacent to its existing service territory. It cited continued high bids from financial parties in T&D assets as the primary impediment to expansion. This stands in contrast to peers AES and DUK which remain committed to divestment (AES via its Brazilian utilities, which it perceives as too risky from a regulatory perspective-- and DUK from its Hydro assets which it sees as driving too much volatility in its earnings). We note the regulatory, F/X, and power price volatility experienced in Brazil are notably different than in adjacent Chile and Peru. Overall, given the lower multiples ascribed to these businesses, we think divestment would appear quite dilutive to perceived P/E (albeit we value the subsidiaries at more depressed 6x EV/EBITDA multiples).

Midstream

Cameron 4: Working towards a 1Q17 date on FID.

Management formally shifted back expectations on a Final Investment Decision (FID) on Train 4 to end of 1Q17. This follows a previous delay of its contracting efforts from its prior Analyst Day tied to 2016. Efforts appear to remain underway as management has opted to continue to pursue development costs as an ongoing item in 2016 net income (driving a substantial drag on the overall Gas business; this drag is in part the delta in driving down 2017 results in addition to a partial year of LNG import contributions). Bottom while mgmt is more constructive on the outlook than earlier this year, it continues to add additional time to contracting window for a FID. Recall mgmt does not appear poised to provide any contracting updates prior to FID.

Mgmt is more constructive on contracting outlook now than 6-months ago

Targeting year-end but providing latitude into 1Q17

Looking at the Pipeline Complement to the LNG Export Story

Mgmt elaborated on its pipeline expansion opportunities to complement the LNG export story, focusing on greenfield and brownfield opportunities via additional compression and looping. While not specific it would appear the magnitude of this opportunity remains material relative to the overall cost of the LNG project. We have not reflected this upside (however undefined) in our current upside scenarios for Cameron 4 development. We continue to view discussion of corresponding gas supply marketing arrangements to complement the LNG Tolling deal as a constructive sign on wider contracting efforts.

LNG Contract would be structured a bit differently

Management stressed that a LNG contract for Train 4 could shift risks such that SRE assumed O&M cost controls (albeit with inflation adjustments). Further, the ongoing permitting costs incurred could not be recoverable under any contract either. While initial contracts would appear to have addressed much of the development risks, the latest shift in terms illustrate the wider oversupply dynamics. We continue to expect an earned ROE on this project to be in the high teens, relative to an extraordinarily high ROE on the initial trains well into the 20% range.

LNG: Prospects for contracts – *and* why the US?

Executives from Sempra continued to favor US LNG versus other sources. Not only was the prospect for Japanese nuclear recovery discussed (or lack thereof, driving more gas demand), but also continued confidence on a protracted low and abundant gas outlook in the US.

Among the other angles discussed given the latest glut was flexibility in gas liquidation. In other supply markets, executives stressed the need to take physical delivery of gas. In the US, potential off-takers would have the flexibility to monetize any committed gas volumes back into the US pool rather than taking physical delivery.

ECA: Mexican Opportunity gets clarity from DOE

While there were no updates on contracting, among the key regulatory hurdles addressed of late was approval from the DOE to pursue exports of US gas via LNG projects based outside of the US. While the decision was focused on competing Canadian opportunities, this was a gating item to the project. The company is laying down initial groundwork (technical studies, regulatory backdrop, etc) for potential longer term (5 year+) decision to shift from import to export terminal, but would need to see sufficient LNG demand which is largely dependent on international developments over the next several years.

Port Arthur: Working with Woodside, but limited progress for now

There were few if any tangible datapoints on this greenfield LNG expansion project. We view this remains a long-dated opportunity likely only once the export opportunity window re-opens.

Renewables: Modest Growth

Management continues to focus on modest renewables growth, albeit with net income largely flat through the forecast period. The equity capital committed to investments remains quite modest and would appear more driven by cash considerations than EPS benefits. As a reminder, mgmt does *not* recognize ITC-related benefits at once – and rather amortizes these benefits across the life of the asset life. Mgmt strategy towards renewables appears to remain largely a higher-yield use of its near-term cash balances, creating a positive NPV when inclusive of its tax credits.

Notably, competition was stressed as being more competitive in wind than solar. This would appear in contrast to the conventional wisdom in the renewable development space thus far. Overall returns targeted are in the mid to high single digit levered returns (~7%). We attribute this relatively more attractive return profile for solar to the existing infrastructure available to Sempra, including potential for additional solar arrays at its Mesquite and Copper Mountain sites. With flat guidance at the segment through 2020, we do not expect this segment to meaningfully move the needle, adding projects selectively. We flag a 100MW PPA with CMS in Michigan with the Analyst Day as an intriguing expansion of its renewable efforts further to the east.

Southern Company

On a longer-term basis the question is whether large cap traditional safety names will begin to lose their reputation as safe havens as the earnings mix continues to evolve. While the latest M&A has been significant for Southern, we still see investors' attention focused on the large capital projects (Kemper IGCC and Vogtle nuclear) with Kemper entering a particularly critical month ahead of its target in-service later in 3Q.

We forecast 2Q16 adjusted EPS of **\$0.72** vs \$0.71 in 2Q15 and \$0.71 Consensus.

- **Key Drivers:** Higher rates in Alabama and Mississippi form the foundation of growth in 2016; however, much of the gains could be offset by higher expenses, primarily D&A and O&M.
- **Wildcard Factors:** (1) Sales growth in the south due to exposure to export activity and (2) magnitude of O&M change following mild winter

SO is guiding to an approximately flat quarter YoY as higher expenses offset

Figure 198: SO 2Q16E Earnings Walk

Southern Company 2Q16 Earnings Walk	EPS
2Q15A Adjusted EPS	\$0.71
Weather vs Normal in 2Q15	(0.03)
Weather vs Normal in 2Q16	0.01
Retail Sales Growth	0.01
Wholesale Operations	(0.01)
Rate Relief	
GA: Base Rate Step-Up Jan 2016	0.02
GA: Nuclear Cost Recovery Tariff	0.00
MS Power: Rate increase Jan 2016	0.03
MS Power: Performance Evaluation Plan	0.00
MS Power: AFUDC on Kemper	0.00
Gulf Power: Capacity and Environ.	0.01
Alabama Power: Rate CNP Compliance	0.04
Alabama Power: Rate Stabilization	0.00
Southern Power	0.02
Interest Expense	(0.01)
Non-fuel O&M: 3.0-3.5% YoY Increase	(0.04)
Other Income and Deductions	(0.01)
D&A	(0.03)
Share Dilution	(0.01)
2Q16E Adjusted EPS	\$0.72
2Q16 Guidance	\$0.70
2Q16 Consensus	\$0.71
2016 UBSe EPS	\$2.83
2016 Consensus	\$2.85
2016 Guidance	\$2.76-\$2.88

Source: Company Filings, FactSet, and UBS Estimates

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

[7/11/16 The Twin Juggernauts Strike A Deal](#)

[4/28/16 Managing the Risks](#)

[2/5/16 More Cash But a Lower Profile](#)

[11/3/15 Focus on Mississippi Elections](#)

[8/26/15 Doubling Down on Atlanta](#)

[7/30/15 August Calendar Heating Up](#)

[7/10/15 Getting Messy in Mississippi](#)

What are the key updates for SO?

- **Southern under scrutiny on the Kemper project grows:** On July 5th the New York Times published an article focusing on Southern Company, specifically its Plant Ratcliffe (Kemper County) Integrated Coal Gasification Combined Cycle (IGCC) project. The report includes statements made by a former engineer at the plant who was, per the OSHA, wrongfully terminated by SO. The employee has alleged that the public disclosures about the construction were inaccurate and misleading. Southern has responded to the report saying that it investigated claims and the article has a “pre-determined objective and tone”. We believe that the latest high-profile allegations in addition to the SEC investigation will further raise regulatory scrutiny of the project. In the recently released May status report the estimated project cost increased by \$10Mn while two key milestones were delayed (see Figure). July will be a critical construction month based on the disclosed milestones targeted for both Trains A & B.

Mgmt stated it was expecting syngas production by July 15th and achieved that milestone via a press release. With the earnings call set for July 27th we expect material updates on where construction stands and if there are further delays.

Figure 199: Kemper IGCC Monthly Status Reports: Milestone Delays

Kemper IGCC Monthly Status Reports					
Key 90-Day Milestones	Dec 2015	Feb 2016	March 2016	Apr 2016	May 2016
Lignite Dryers Ready for First Lignite Feed	February 2016	May 2016	May 2016	June 2016	June 2016
LDF Non-Dome	February 2016	April 2016	May 2016	May 2016	July 2016
WSA Commissioning	N/A	May 2016	June 2016	July 2016	July 2016
AGR Commissioning - Train A	April 2016	May 2016	July 2016	July 2016	July 2016
Refractory Cure - A	April 2016	July 2016	July 2016	July 2016	July 2016
First Lignite Feed - A	April 2016	July 2016	July 2016	July 2016	July 2016
First Syngas Production - A	April 2016	July 2016	July 2016	July 2016	July 2016
Reliable/Clean Syngas Available - A	N/A	July 2016	Aug 2016	Aug 2016	Aug 2016
First Syngas Production - B	N/A	May 2016	June 2016	July 2016	July 2016
AGR Commissioning - Train B	N/A	May 2016	June 2016	June 2016	July 2016
Reliable/Clean Syngas Available - B	N/A	June 2016	June 2016	July 2016	July 2016

Source: Company filings, MPSC Docket 2009-UA-0014

Recall that SO previously announced further delays to the target in-service date to August 31, 2016 (from June 30) for the Kemper IGCC plant with an additional \$110M of unrecoverable costs. Delays beyond August 31st are expected to incur ~\$25-\$35Mn monthly ‘base costs’ (subject to the cost cap) and ~\$15Mn expenses not subject to the cost cap. (Docket 2015-UN-0080)

- **Timing of the Mississippi rate case will be the next key issue:** We look for further clarity on exactly when management will declare in-service and file the associated rate case with the Mississippi Public Service Commission (PSC) given the significant monthly costs associated with the plant. Management has indicated that despite a targeted in-service date of August 2016, the associated rate case filing could be made approximately 3-5 months following formal in-service. We see this ‘lag’ as being used to address any issues with the plant and allowing the plant to reach a more ‘normal’ production level. For example, Duke’s Edwardsport plant was nominally placed into service the plant suffered from consistent low capacity factors on its ability to use syngas generated for a protracted period, ultimately driving pressure from the IURC to disallow certain operating costs. We expect stakeholders to focus not just on the nominal capacity factor but how often the plant is running on syngas compared with traditional fuels.

Recall that its current rate agreement would allow the company to defer costs even after it reaches in-service (depreciation) into the pending case.

Management estimates that after a 15% rate increase in December (plus refund checks), another sizeable rate increase will be necessary once in-service, although this could be offset with tax credits and grants.

- **Georgia PSC Staff views project schedule as “extremely challenging”:**

The leaders of the Georgia Public Service (PSC) Staff oversight of Vogtle 3 & 4 (Independent Construction Monitor; ICM) indicated that it sees a high probability that Southern will not be able to achieve the in-service data for Units 3 (June 2019) and 4 (June 2020) in its testimony from June 17th. Production for January – May 2016 has not been achieved per the ICM and it does not believe that the assumption of future mitigation is supported. The ICM Dr. Jacobs recently visited the Sanmen nuclear development project in China which is ~2 year ahead of Vogtle’s timeline where Dr. Jacobs noted that it appears challenging to compensate for lost time with additional resources due to limited physical space to conduct work. The ICM also believes that it is “highly unlikely” that Southern will complete Unit 4 by year-end 2020, putting the nuclear tax credits at risk.

“We conclude that the Company has not demonstrated to Staff that the current CODs [commercial operation dates] have a reasonable chance of being met. It is our opinion that there exists a strong likelihood of further delayed operation dates for both Units.” - Georgia Public Service (PSC) Staff Independent Construction Monitor

The ICM recommends the approval of the \$160Mn of expense for Vogtle Construction Monitoring (VCM) report 14 expenses. The Georgia PSC approved Southern’s full \$148Mn request on February 19 for the VCM 13 report covering 1H15 expenses. (Docket 29849)

- **Latest report shows higher costs but stable timeline:** In contrast to the ICM’s testimony, on April 5th Georgia Power submitted a Supplemental Information Report (SIR) for Vogtle arguing that all costs incurred for the projects through the April 5th filing were prudent and that management believes the forecasted costs are “reasonable”. Although Georgia Power’s share of the total project costs have increased to \$5.44Bn from \$4.42Bn originally, going forward SO estimates that the total rate increase for Vogtle will be 6-7% with ~4.5% already included in rates versus up to 12% excluding CWIP originally forecasted. The ultimate consumer bill impact could be greater if the units are not eligible for tax credits as the ICM warns.

- **Recertification of the higher cost structure is a management goal:** Georgia Power has been working behind-the-scenes with the Georgia PSC Staff on the schedule review and an update is expected by mid-October. Management would like for the Commission to recertify the latest estimated project cost of \$5.4Bn versus the \$4.4Bn original capex forecast. Recertifying the latest project estimate would help reduce the risk but the high potential for further timeline slippage is a greater concern in our view.

Specific areas for risk mentioned in the report include the containment equipment.

The VCM 14 report includes a +\$395Mn cost due primarily to the EPC settlement.

It remains to be seen how the Commission will treat and rule on the Westinghouse settlement

Figure 200: Capital Forecast at Georgia Power Company Ownership Percentage (\$Mn)

Capital Forecast at Georgia Power Company Ownership Percentage (\$Mn)			
Original Capital Forecast			\$4,418
Changes through VCM 13		627	(A)+(B)
Currently Field Capital Forecast			\$5,045
Proposed VCM 14 Changes: EPC Scope Change			
Settlement		326	
Cyber Security		46	
Resolution of Open Notices of Change		23	
Total Proposed Changes for VCM 14 with Settlement			395 (C)
Capital Forecast Proposed for VCM 14			\$5,440

Change Including Escalation			
Capital Cost Category (\$Mn)	VCM 1-8	VCM 12	VCM 14
Power Block and Support Structure			
Construction	\$24	\$17	\$0
Federal Regulation Changes	32	25	21
Settlement	0	0	350
Taxes and Fees	50	53	0
Operational Readiness	91	48	24
Owners Quality and Compliance	152	75	0
Legal/Environmental Permit/Misc.	12	29	0
Transmission	19	0	0
Total Changes from Original Certification	\$380 (A)	\$247 (B)	\$395 (C)

Source: Company Filings

- **KMI and SO Agree to \$4.15B JV for SNG:** Kinder Morgan (KMI) and Southern Company (SO) announced an agreement on Sunday for KMI to sell a 50% stake in its Southern Natural Gas (SNG) pipeline system to SO. KMI will continue to operate the system and the two companies have committed to work together in pursuit of specific growth opportunities to develop natural gas infrastructure for the strategic venture. Following SO's recent AGL acquisition, SO is now a ~50% customer on the system and as a partner is well incentivized to work with KMI in pursuit of growth opportunities. The transaction has an estimated EV of \$4.15B implying the \$1.47B value for SO's 50% share of the equity interest and \$1.2B of debt. According to FERC, SNG EBITDA in 2015 was ~\$400mm which implies ~10.4x 2015 EV / EBITDA 2015.
- **How accretive is the deal to SO? Looks reasonable on P/E too.** Without disclosing leverage and prospective FCF/Earnings of the acquired asset, we rely on \$148 Mn in 2015 FERC Net Income per Form 2 Data (~\$75Mn @ 50%). This would imply ~20x trailing P/E without accounting for further SO holding company leverage. The \$4 Bn disclosed EV and above net income includes \$1.2 Bn of asset level leverage. We think the deal is likely a good one for SO, with the peer group trading in-line at 20x 2016E P/E already. Further with \$328 Mn in '15 CFO, we see ~\$400Mn+ in additional HoldCo leverage capacity off a ~mid-teens FFO/debt target (\$600 Mn of OpCo leverage exists already at 50%). As such, we see the equity piece for SO initially at ~\$1 Bn. Note historical results have been stable, consistent with contracted asset base.

In the last year we have seen SO invest in gas LDCs (\$8Bn for AGL), its unregulated Southern Power business focused on gas and solar (\$2.5+Bn equity in Southern Power), and the Kinder Morgan transaction is the latest move in that direction.

EPS Estimates unchanged

Below we present our EPS estimates which do not formally include any potential accretion from the AGL Resources acquisition but we show illustratively the estimated accretion. Further details on the accretion profile are available in our previous note [‘Doubling Down on Atlanta’](#).

Figure 201: Southern Company EPS Estimates

SO EPS Estimates	2014A	2015E	2016E	2017E	2018E	2019E
Alabama Pow er	\$0.85	\$0.88	\$0.86	\$0.87	\$0.95	\$1.00
Georgia Pow er	\$1.37	\$1.40	\$1.44	\$1.48	\$1.53	\$1.59
Gulf Pow er	\$0.16	\$0.16	\$0.19	\$0.19	\$0.19	\$0.20
Mississippi Pow er	\$0.25	\$0.25	\$0.27	\$0.28	\$0.30	\$0.34
Southern Pow er	\$0.19	\$0.24	\$0.24	\$0.20	\$0.16	\$0.10
Other	(\$0.01)	(\$0.04)	(\$0.18)	(\$0.17)	(\$0.16)	(\$0.15)
SO, UBS Estimates	\$2.80	\$2.89	\$2.83	\$2.85	\$2.97	\$3.08
		3.0%	-2.0%	0.8%	4.2%	3.5%
Guidance Range	\$2.76-\$2.88		\$2.76-\$2.88			
3-Yr EPS CAGR off 2016E Midpoint (\$2.82) without AGL						3.0%
Estimated Potential Accretion from AGL & Staggered Equity				\$0.12	\$0.07	\$0.07
3-Yr EPS CAGR off 2016E Midpoint (\$2.82) with AGL						3.7%
Prior UBS			\$2.83	\$2.85	\$2.97	\$3.08
Standalone guidance midpt (adj for bonus and dilution)			\$2.82	\$2.83	\$2.93	\$3.03
Street Consensus			\$2.84	\$2.97	\$3.08	\$3.17

Source: Company filings, FactSet, UBS estimates

Valuation: Increase Price Target \$6 to \$51

Our valuation is based on a 2018E sum-of-the-parts analysis. The increase in our Price Target is driven by the expansion of the regulated utility peer group P/E to 17.7x from ~16x previously. We continue to apply significant discounts to the subsidiaries with elevated regulatory and execution risks (Vogle and Kemper).

Figure 202: Southern Company Sum-of-the-Parts Valuation

Southern Company Valuation (UBSe)		Downside Case		Base Case		Upside Case	
Business Segment	2018E EPS	Valuation Multiple	Per Sh. Value	Prem/Discount	Valuation Multiple	Per Sh. Value	Valuation Multiple
Regulated Business							
Alabama Power	\$0.95	16.7x	\$15.87	0.00x	17.7x	\$16.82	18.7x
Georgia Power	\$1.53	15.2x	\$23.27	-1.50x	16.2x	\$24.80	17.7x
Gulf Power	\$0.19	16.7x	\$3.25	0.00x	17.7x	\$3.45	18.7x
Mississippi Power	\$0.30	14.2x	\$4.29	-2.50x	15.2x	\$4.59	17.7x
Southern Power (Contracted Merchant)	\$0.16	15.7x	\$2.50	-1.00x	16.7x	\$2.65	17.7x
Other	(\$0.16)	16.7x	(\$2.72)	0.00x	17.7x	(\$2.88)	18.7x
Potential Accretion from AGL	\$0.07	15.7x	\$1.10	-1.00x	16.7x	\$1.17	18.7x
Southern Company Total/Implied	\$3.04	15.8x	\$48.00		16.8x	\$51.00	18.1x
Shares Outstanding (2018E Mn)				942	Overall discount		
Regulated Peer Group Multiple				17.7x	-5.3%		

Source: Company filings, FactSet, UBS estimates

Talen Energy Corp.

The 'go-shop' period expired on July 12th without a superior proposal and now management's focus is on completing the necessary regulatory filings to facilitate closing the transaction by YE16.

TLN intends to host a 2Q16 earnings call at this time.

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

[6/3/16 Riverstone Steps In](#)
[5/12/16 Shifting the Capital Allocation Timeline](#)
[4/25/16 How Much Room is Left?](#)
[4/5/16 Many Options On The Table](#)
[3/9/16 A Call to Action](#)
[2/25/16 How Will Capital Be Allocated?](#)
[1/7/16 Will 2016 Offer a Turnaround?](#)
[11/16/15 Riding the Power Curve](#)
[10/26/15 Unpacking the Latest Portfolio Developments](#)
[10/9/15 Extracting Top Dollar on Divestments](#)
[9/18/15 Capacity Auction Misses The Mark](#)
[8/18/15 Tapping Into Gas Conversions](#)
[8/7/15 Traveling on Calmer Waters \(Upgrade to Neutral\)](#)
[7/21/15 Deploying The War Chest](#)
[7/20/15 Opening The War Chest?](#)

What are the key updates for TLN?

- **No superior offers received:** On July 12th Talen disclosed in a 14A filing that it did not receive a superior offer during the 40-day 'go-shop' period and is moving forward with the \$14/sh Riverstone transaction announced on June 3rd. The NRC change of control filing was made in late June with the FERC and other regulatory filings expected in July/August.
- **We continue to believe that shareholders will approve the transaction:** The scenario under which a deal might not be approved is if commodities rallied prior to shareholder approval date such that the bid was no longer commensurate with the market environment. We do not believe there is an analogy to Blackstone's previous bid for Dynegy in 2010 in which shareholders launched a campaign to rebuff the perceived low bid for the company. We emphasize the PPL/Riverstone received regulatory approvals in 2014/2015 for the merger (approximately year ago). The shareholder votes will be held when the proxy statement is finalized.
- **Colstrip settlement achieved:** Talen and the other joint owners reached a proposed settlement to release liability and lead to retirement of Units 1 & 2 by 2022 with the dismissal of Units 3 & 4 claims. Talen owns 50% of Units 1 & 2 and 15% of Units 3 & 4 through an agreement with NorthWestern. Talen has stated that the Western asset is non-core and is open to exploring alternative ownership agreements.

At the \$14/sh offer price the offer price the implied 2018 EV/EBITDA multiple is ~8x UBSe (7.6x Consensus), representing a strong premium over where peers Dynegy (6.6x) and NRG Energy (6.3x) were trading at the time.

We believe there is a low probability that shareholders reject the proposal.

- **Best Harquahala risk/reward likely involves finding a local solution:**

Management has stated that it believes the best risk/reward is in finding a local solution such as selling the plant to a local utility or entering into a PPA rather than attempting to move the unit. While the cost estimate to relocate the asset has been refined to ~\$315-\$500/kW, if management is able to realize \$500-\$700/kW in value depending on the market for the new plant it would have essentially the same value creation as if it simply sold the asset for ~\$200-\$250/kW without the risk of transportation.

The plant was built in a modular way, has three independent units, and TLN has been working with firms that specialize in the type of work so management is not concerned by the prospects of moving the asset; however, we would be surprised if management opts to relocate the asset. In the interim Talen is attempting to improve the cost structure of the plant and reduce the EBITDA drag which is estimated to be \$5-10Mn.

Further details on the desert Southwest market are available below:

[6/17/16 The Wild, Wild West](#)

[7/11/16 Can Utilities Avoid A Summer Swoon?](#)

We're biased to believe the asset is able to get a contract – rather than moving

Management has previously indicated it would address the future of this plant in 2016E

It would appear the cost of transporting the plant could approach ~\$350/kW

Valuation: Maintain \$14 Price Target

Our valuation methodology continues to be based on the Riverstone offer price.

WEC Energy Group Inc.

With no material rate cases expected in the near-term (WI no longer anticipated in 2016), the focus remains on incremental capex opportunities to address the capex 'cliff' in 2018 which management has committed to updating the outlook by EEI (November). While we do not expect a quantitative update on the capex 'backlog' on the 2Q call, we expect a continued discussion on the opportunity set available to offset the impact of bonus depreciation (already approximately half addressed).

We forecast 2Q16 adjusted EPS of **\$0.58** vs \$0.59 in 2Q15 and \$0.58 Consensus.

- **Key Drivers:** We expect the Integrys transaction to be a net drag on the quarter given the seasonality of the gas-focused utility. Historically only 10-15% of Integrys' earnings are in the second quarter (earnings are weighted towards the winter months) but there could be a full quarter of dilution from the transaction financing. We see this as a primary reason why earnings are forecasted to decline YoY despite the TEG transaction and incremental rate relief in Wisconsin.
- **Wildcard Factors:** (1) How conservative is guidance? Historically WEC has beaten both its guidance range and Consensus expectations in quarters without significantly unfavorable weather and we expect results to beat guidance once again; (2) Magnitude of cost reductions/merger initiatives and O&M discipline to more than offset organic increases in overhead

After navigating a warm winter in 1Q16, we a relatively quiet 2Q but highlight the Integrys acquisition has skewed the earnings profile away from 2Q/3Q and into 1Q/4Q.

Figure 203: WEC 2Q16E Earnings Walk

WEC Energy 2Q16 Earnings Walk	EPS
2Q15A Adjusted EPS	\$0.59
Weather vs Normal in 2Q15	\$0.00
Weather vs Normal in 2Q16	\$0.01
Sales Growth: ~30bp	\$0.00
Rate Relief	
Michigan Gas - MI	\$0.00
Wisconsin Public Service Corp - WI	(\$0.01)
Minnesota Energy Resources - MI	\$0.01
WEPCO & Wisconsin Gas - WI	\$0.04
O&M and Other Benefit Reductions	\$0.00
American Transmission Co. (ATC)	\$0.01
Power The Future (PTF)	\$0.01
Interest Expense (Ex. TEG)	\$0.00
D&A (Ex. TEG)	(\$0.01)
Net Contribution from Integrys	\$0.08
Dilution from Integrys	(\$0.16)
Parent	\$0.00
2Q16E Adjusted EPS	\$0.57
2Q16 Consensus	\$0.58
2Q16 Guidance	\$0.51-\$0.55
2016 UBSe EPS	\$2.94
2016 Consensus	\$2.93
2016 Guidance	\$2.88-\$2.94

Source: Company Filings, FactSet, and UBS Estimates

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

[5/9/16 Upgrade to Neutral on Capex and Valuation](#)

[2/16/16 Integrating Integrys](#)

[11/6/15 Inflection in Spend](#)

[10/26/15 Letting Out Some Steam \[Downgrade\]](#)

[7/30/2015 New Beginnings](#)

[5/16/2015 Running Towards the Finish Line](#)

What are the key updates for WEC?

- **Accelerating capex to offset bonus depreciation:** Management announced \$500Mn of higher capital spending for 2016/2017 on its 1Q16 call as WEC continues to explore opportunities to deploy the ~\$1Bn of deferred tax cash benefits from the five-year extension of bonus depreciation. In our recent meeting with management it was stressed that management was confident it could replace any projects that were pulled forward (i.e. spending would be incremental to the base plan). While management was confident that it could find attractive capital spending opportunities, we think an alternative option is to reduce higher-coupon borrowings to improve the earnings outlook in that manner. We believe possible areas for additional spending include (1) the potential acquisition of approximately 30bcf of gas storage facilities in Wisconsin that are currently leased [unquantified today]; (2) spending on gas storage safety [~\$30Mn]; and (3) investment in Enterprise Resource Planning (ERP) and other accounting systems [\$100-\$150Mn]. A further area is additional spending under the accelerated pipeline replacement program (AMRP), currently \$250-\$280Mn annually, but management has commented that there are natural limitations on how much road work can be feasibly be conducted in a given time period.

- **Potential to stay-out of rate cases due to merger initiatives:** On the 1Q16 call management announced that it would not file a rate case in 2016 (2017 test year) for its Wisconsin utilities, subject to action by the Public Service Commission of Wisconsin. Management is still evaluating the timing of the next rate cases in the state but is hopeful that it can avoid increasing customer base rates by executing on its merger initiatives. For example management has highlighted opportunities in areas ranging from operations, IT, and reducing staffing levels to lower O&M costs. As part of the Integrys merger Wisconsin Gas and Wisconsin Electric each agreed to three years of earnings sharing such that if the utilities over-earn, the first 50bp will be shared equally with customers.

Minnesota Energy Resources filed a \$15Mn case in September 2015 and implemented rates in January subject to refund. Peoples Gas and North Shore Gas have base rate freezes through July 2017 as part of the merger conditions. With the majority of the spending in Illinois recoverable under the AMRP, we believe the base rate freeze to continue.

- **Resolution in Peoples Gas investigations:** In May WEC agreed to pay \$19Mn to settle legacy claims relating to allegations of misleading statements regarding the cost estimates for the AMRP in Illinois and management has reported better coordination with the city and an improvement relationship. Overall we are encouraged by the fact that People's Gas earned its allowed ROE in 2015 (9.05%) and we look to see if management can deliver repeat performance in 2016.

With the benefit of time to work on its capex schedule incorporating bonus depreciation cash we expect WEC to move 'backlog' projects into its base plan

WEC broadly discussed staffing, IT, supply chain, customer service, and operations as areas of focus following the TEG merger but has not quantified

We continue to include 3% non-fuel O&M savings in our run-rate estimates (\$0.15-\$0.20 of O&M).

As a reminder the latest target cost is now ~\$6.8Bn through 2030 and ~\$7.8Bn through 2040

EPS estimates: Capex updates to firm up visibility

We show below our earnings forecast with WEC standalone in 2014/2015 and combined WEC+TEG in 2016+. Our estimates continue to be largely in-line with Consensus and reflect a ~6% CAGR 2016-2020, in-line with the midpoint of the guidance range. We recently adjusted our dividend per share estimates to be more consistent with estimated earnings growth, also consistent with commentary from management. We assume that management will keep the payout ratio towards the midpoint of the 65-70% payout ratio range (67-68%); however, Consensus implied payout ratio in 2019E is 70%.

Management expects its utilities to earn their allowed ROEs as they did in calendar 2015

Figure 3: WEC EPS estimates vs. pro-forma for the merger with TEG, 2014A-2020E

WEC Energy Group Inc. EPS	2014A	2015A	2016E	2017E	2018E	2019E	2020E	CAGR '16-'20
UBSe Combined Entity	\$2.65	\$2.73	\$2.94	\$3.12	\$3.33	\$3.52	\$3.70	6.2%
UBSe (Prior)	\$2.65	\$2.73	\$2.94	\$3.12	\$3.33	\$3.52	\$3.70	
Consensus			\$2.93	\$3.11	\$3.30	\$3.48	\$3.70	
Embedded synergies assumption % of O&M (UBSe)		-0.5%	0.5%	1.0%	1.5%	2.0%	3.0%	
Embedded synergies assumption (UBSe)		\$0.00	\$0.03	\$0.05	\$0.08	\$0.11	\$0.16	
EPS Guidance			\$2.88-\$2.94		5-7% EPS Growth beyond 2016			
Low-End of Guidance Range (5%)			\$2.88	\$3.02	\$3.18	\$3.33	\$3.50	
High-End of Guidance Range (7%)			\$2.94	\$3.15	\$3.37	\$3.60	\$3.85	
Midpoint of Guidance Range (6%)			\$2.91	\$3.08	\$3.27	\$3.47	\$3.68	6.0%
Dividend (UBSe)	\$1.56	\$1.83	\$1.98	\$2.10	\$2.23	\$2.36	\$2.50	
Dividend Growth		17.3%	8.2%	6.0%	6.0%	6.0%	6.0%	
Payout Ratio	59%	67%	79%	67%	67%	67%	68%	
Dividend Guidance			Targeting 65%-70% payout; grow dividend in-line with earnings					

Source: Company filings, FactSet, UBS estimates

Valuation: Increase Price Target \$5 to \$63

Our valuation is based on a 2018E P/E methodology with a 5% premium. The increase in our valuation is driven by the expansion of the peer P/E multiple to ~18.0x from ~16.7x when we conducted our last mark-to-market for WEC.

Figure 204: Updated WEC Energy Valuation

WEC Energy Group Valuation: P/E Derived on 2018 EPS			UBS
Downside Case	Base Case	Upside Case	
Valuation	Price Target	Valuation	
2018 EPS 3.18	2018 EPS 3.33	2018 EPS 3.37	
Low-end of 5-7% EPS CAGR	Using UBSe Estimate	High End of 5-7% EPS CAGR	
Regulated Utility	Regulated Utility	Regulated Utility	
Group P/E Multiple 17.9x	Group P/E Multiple 17.9x	Group P/E Multiple 17.9x	
Premium 0%	Premium 5%	Premium 15%	
Value \$57.00	Value \$63.00	Value \$69.00	
**Rounded			

Westar Energy

The upcoming report (July 25th) from the Missouri PSC regarding the pending transaction will be a critical datapoint for the merger and pro-forma company outlook. We do not forecast any significant difficulty with Kansas approval but broader questions remain about the ability to retain \$150+Mn annual synergies in the long-run.

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

[5/31/16 Connecting in Kansas](#)

[5/5/16 Unlikely to Buy into Kingman](#)

[2/29/16 Bonus Blows Away Some Wind Growth](#)

[1/25/16 Winning With Wind?](#)

[11/5/15 Fair Winds into 2016](#)

[10/8/15 A Compassionate Clean Power Plan](#)

[8/6/15 Where will the ROE Land?](#)

What are the pivotal questions for WR?

- **Significant synergies on tap:** On June 28th Great Plains Energy (GXP) and Westar Energy (WR) filed with the Kansas Corporation Commission (KCC) for merger approval starting the 300-day statutory clock and initiating what we believe will be the key regulatory approval in the transaction. The companies estimate significant synergies with \$150Mn net savings in 2019 (\$124Mn O&M and \$25Mn capital) and \$175Mn in 2021+. In our note [analysing the transaction](#) we assumed 4% of combined O&M could be retained by GXP (\$50Mn) and the critical factor will be how long the combined company will be able to go without a rate case before the lower cost structure is reflected in rates. On a standalone basis we expected Westar to file its next full rate case in mid-to-late 2018 to recover the costs associated with its wind acquisitions.

Westar and Great Plains are forecasting significant synergies in the transaction: the question is how much of the benefits will be retained by shareholders and for how long.

The transaction is expected to close in the Spring of 2017 based on the statutory clock in Kansas.

Docket 16-KCPE-593-ACQ

Figure 205: GXP-WR Net Merger Savings (\$Mn)

GXP-WR Net Merger Savings (\$Mn)					
	2017	2018	2019	2020	2021+
Non-Fuel O&M					
Generation	\$0	\$6	\$33	\$70	\$80
T&D / CS	\$5	\$5	\$5	\$5	\$5
Shared Services	\$5	\$21	\$22	\$23	\$25
Supply Chain	\$3	\$21	\$64	\$64	\$65
Total Non-Fuel O&M	\$13	\$53	\$124	\$162	\$175
Capital	\$3	\$11	\$25	\$36	N/A
Total	\$16	\$64	\$149	\$198	\$175

Source: Company Filings

- **What will Missouri require?** Separately, attention in the merger relates to the Missouri PSC investigation into the transaction where a report is expected by July 25th. The PSC Staff requested that the docket be opened to assess the potential impact on Missouri customers as part of the GXP/WR merger. Many investors remain concerned about the potential for the PSC to adjust the utility rates due to the higher level of pro-forma parent leverage in the transaction.

The shareholders meetings are expected to be in late 3Q/early 4Q.

Ringfencing appears to be the immediate focus with the regulatory seemingly concerned about any negative perceived impacts of the acquisition. The wider question remains whether the transaction highlights the limited opportunity to reinvest in the state – will either the PSC or the legislature act to bring an opportunity for an accelerated spending schedule in the state remains the key wild card for many investors.

Docket: EM-2016-0324

Xcel Energy

Note: we consider Xcel a regulated utility but are including here due to discrete timing issues associated with yesterday's regulated preview.

- **Key Drivers:** Ongoing \$0.06 D&A drag remains a headwind into the quarter though several ongoing ratecases and marginal sales growth should offset in the quarter.
- **Wildcard Factors:** Ongoing Minnesota rate case could have implications for regulatory reserve needs in light of recent Department of Commerce (the lead intervenor in the case) recommendation for ~\$95M revenue requirement versus XEL request for \$164M. Midpoint suggests ~1 cent offset to Minnesota YoY benefit.

Figure 206: XEL 2Q'16E Earnings Walk

XEL 1Q16 Earnings Walk	EPS
Reported 2Q15A EPS	\$0.39
Normalized Weather	\$0.01
Normalized 2Q15A EPS	\$0.40
Weather Impact	\$0.00
Sales Guidance (+0.5% elec)	\$0.02
Rate Cases	\$0.04
Capital Rider Revenue (55-65M increase)	\$0.02
D&A	(\$0.06)
Interest (40-50 increase 2H loaded)	(\$0.01)
Taxes	(\$0.01)
O&M (Increase 0-1%)	(\$0.01)
AFUDC (Increase 0-5M)	\$0.00
Other	\$0.00
Dilution	(\$0.00)
2Q16 EPS	\$0.39
2Q16 Consensus	\$0.41
2016 Earnings Guidance	2.12-2.27
2016 UBSe	\$2.20
2016 Consensus	\$2.20

Source: Company Filings, Factset, UBSe

What are the Key Issues to Watch at XEL?

- **600MW Ratebased Wind Intervenor Testimony is due on July 27:** A decision is expected in the case by November timeframe with hearings scheduled Sept 7-9. The company continues to remain relatively confident around passage of the proposal, which equates to \$1B ratebase in the upside capex plan.

- **Acquisitions for repowering wind?** Mgmt stated recently it could well seek to acquire and repower legacy PPA arrangements from the original set of contracts signed in the Dakotas and MN from its earliest vintage. This raises the question of what will come of all the presently non-ratebase renewable generation across service territories. The repowering opportunity is highlighted on the back of the latest IRS guidance on thresholds to requalify assets for a new round of PTCs
- **Colorado ERP Filed May 27 – More Renewables to Come:** Xcel filed its 2016 Electric Resource Plan on May 31 and outlined ~615MW of new capacity needs through 2023. The new generation will be sourced through competitive solicitation after July 2017 if approved. Further, we note the 615MW is *after* accounting for the 2017 renewable energy plan (proceeding 16A-0139E), the solar connect program, and the 600MW Rush Creek wind project. In fact, XEL explicitly says it will *not* accept coal plant proposals as part of the process. Total capacity needs are weighted in the early 2020s, with ~284MW needed in 2022 and 615MW cumulative in 2023. There is no schedule posted at this point for the key dates between now and July 2017.

Management emphasized recently that it could yet participate in further self-build opportunities of up to 50% of cumulative opportunities (emphasizing wind), if it could show *wider* economic benefits (not to just consumers, but also the state) as it has an existing relationship with Vestas in the state of WI.

- **Gas ratebase withdrawn:** While we had viewed gas reserve ratebasing as a riskier proposition from the start, we note the company's recent withdrawal of application comes on the back of a rejection for similar proposition from Black Hills and conversations with intervenors. ~\$300M was associated with natural gas reserves in XEL's upside capex case.
- **Minnesota IRP Updates:** With intervenor testimony due July 8, we look to NPSM reply comments on August 12 and anticipated decision in 2H'16 for finalization of the IRP. We show below the capacity additions under the revised long term resource plan as well as the generation mix now and in 2030 envisioned in this plan (in the table below, XEL shows the North Dakota CT coming on line in 2023 for planning).

Gas reserve ratebasing proposal was withdrawn recently; ~\$300M of nat gas reserve investment was contained in the ~\$2.5B upside capex plan

Figure 34: Revised Proposal Expansion Plan (MW Additions)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Large Solar	-	-	-	200	-	200	100	100	100	100	100	100	-	400	-	-	1,400
Wind	-	-	-	-	800	-	-	200	200	-	400	200	-	-	-	-	1,800
North Dakota CT	-	-	-	-	-	-	-	-	232	-	-	-	-	-	-	-	232
Sherco Gas Conversion/CT	-	-	-	-	-	-	-	-	-	-	562	-	-	-	-	-	562
Sherco CC	-	-	-	-	-	-	-	-	-	-	-	778	-	-	-	-	778
CT	-	-	-	-	-	-	-	-	-	-	-	464	-	-	-	-	464
CC	-	-	-	-	-	-	-	-	-	-	-	-	778	-	-	-	778
Total MWs	-	-	-	200	800	200	100	300	532	100	1,062	1,542	778	400	-	-	6,014

Source: Xcel Energy filing, Docket E002/RP-15-21

What are the prospects for increased capex?

XEL's \$2.5Bn 2016-2020E upside capex plan includes opportunities that span the risk spectrum including from grid modernization (higher probability of success) to \$300M for ratebasing natural gas reserves (recently withdrawn as noted above). We specifically focus on solar where we see the extension of the Investment Tax

Credit (ITC) as benefitting unregulated developers who do not have to normalize the ITC and therefore can offer more attractive customer benefits.

The 600 MW of ratebased wind under a competitive exemption in Colorado is separate from the IRP filing but would be counted towards its goals, contributing \$1B of the \$2.5B "upside" to the base capital plan. Potentially another 100 MW of solar could be too, but we don't expect a decision to pursue it until 2017. Although this \$1B is somewhat higher than the \$850M embedded within the \$2.5B upside (plus more from ratebased solar), we don't expect management to increase the upside range given pushback against ratebased gas and other possible "takes". **We still see it as challenging to execute on ratebase solar capex for all utilities following the ITC extension, with XEL among the few explicitly reflecting it in their plans.**

If fully implemented through 2020, the \$2.5B upside capex plan would have driven ratebase growth back up to ~5.5% and EPS growth 5.5%-6.0% off a 2015 \$2.10 base (still assuming a 9.4% ROE), though withdrawal of natural gas proposal reduces this somewhat. This would be in-line with the previous upside-case forecast for ~5.6% ratebase growth and 5%-6% EPS growth. However, with much of the upside spending in 2018 and beyond, this leaves management with slower near-term EPS growth and a "show-me" story for 2018+ to justify the average utility multiple XEL now trades at.

- More specifically, the Minnesota Integrated Resource Plan (IRP) includes (among other things) 800 MW of new wind and 400 MW of new solar by 2020.
- Likewise, the recent Colorado energy plan includes 600 MW of wind and 400 MW of solar. This 600 MW will now be owned directly. The 400 MW will remain competitive to solicitation for at least 75%. It is unclear if management will to compete outside of ratebase for the remaining portion ineligible. A maximum of 50% can be ratebased under the current rules, with the threshold being more stringent than the baseline 25% of eligibility assuming the project is broadly competitive; rather the 50% must show tangible customer benefits. We believe the company may yet opt to pursue investment outside of ratebase should it need to pursue growth to offset lost investment opportunities elsewhere as well as concerns around implications for future RFP procurements (we suspect this will ultimately be elected once evaluated in 2017).

Of these totals, only a portion is expected to be ratebased, with the \$2.5B (~100-150 bps of growth) inclusive of about 200 MW of wind and 100 MW of solar in MN and the 600 MW of bid-exempt wind in Colorado. Additionally, up to 50% of solar in Colorado is eligible for ratebase treatment too, with up to 100 MW through a non-competitive exemption under the 2007 law and the remaining 100 MW of solar available to win through an RFP.

Figure 207: XEL EPS Estimates

UBS Estimates (\$/share)	2014A	2015E	2016E	2017E	2018E	2019E	2020E
PSCo	\$0.90	\$0.92	\$0.92	\$0.94	\$0.99	\$1.04	\$1.10
NSPM	0.80	0.85	0.92	0.94	0.96	1.00	1.08
SPS	0.26	0.25	0.30	0.35	0.38	0.42	0.47
NSPW	0.14	0.16	0.14	0.15	0.17	0.18	0.20
XEL Parent	(0.08)	(0.08)	(0.08)	(0.09)	(0.09)	(0.09)	(0.09)
UBSe EPS	\$2.03	\$2.09	\$2.20	\$2.30	\$2.40	\$2.55	\$2.75
CAGR 2015 \$2.10 (mdpt guide) - 20XX					4.6%		5.5%
Guidance			2.12-2.27				4-6%
Previous Ests			\$2.20	\$2.30	\$2.40	\$2.55	
Consensus			\$2.20	\$2.32	\$2.44	\$2.58	

Source: Company Filings, Factset, UBSe

Valuation: Maintain \$42

We are maintaining our \$42PT, consistent with the recent uptick in sector valuation.

Figure 208: XEL Valuation

Business Segment	Valuation Metric	2018 EPS	Low Case		Base Case			High Case	
			Valuation Multiple	(\$/Share) Value	Premium/Discount	Valuation Multiple	(\$/Share) Value	Valuation Multiple	(\$/Share) Value
<u>Regulated Business</u>					Regulated Peers:		17.7x		
Northern States Pow er - Minnesota	P/E	\$0.96	16.2x	\$15.60	0.0x	17.7x	\$17.05	19.2x	\$18.49
Northern States Pow er - Wisconsin	P/E	\$0.17	17.2x	\$2.84	1.0x	18.7x	\$3.09	20.2x	\$3.34
Public Service Colorado	P/E	\$0.99	16.2x	\$15.97	0.0x	17.7x	\$17.45	19.2x	\$18.93
Southw estern Pow er Service	P/E	\$0.38	15.2x	\$5.79	-1.0x	16.7x	\$6.36	18.2x	\$6.93
<u>HoldCo</u>									
Parent & Other Overhead Expense	P/E	(\$0.09)	16.2x	(\$1.53)		17.7x	(\$1.67)	19.2x	(\$1.81)
XEL Equity Value per Share		\$2.40	16.1x	\$39.00		17.6x	\$42.00	19.1x	\$46.00

Source: Company Reports, UBSe

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

[5/13/16 Getting Winded](#)

[2/3/16 Too Much, Too Fast](#)

[12/7/15 Upside from the Analyst Day](#)

[11/2/15 Ramping Up on Renewables](#)

[7/31/15 Executing Well on Regulatory Strategy](#)

[5/4/15 Fighting Off a Case of the Lag](#)

[4/6 In Search of Reform](#)

[1/30 Rocky Mountain Higher](#)

[11/3 Poised for Further Inflection?](#)

AES Corp

We look for management to report **\$0.15** adjusted EPS, a meaningful decline YoY as Outages, reversal of a one-time benefit at Eletropaulo, commodity and F/X headwinds offset much gains from growth projects. We emphasize with few new assets reaching in-service for the relevant period, much of the comparison remains simply capital allocation. **We do not expect a further revision to 2016 EPS guidance following several quarters of continued volatility; further, don't look for a revision predicated on the recent rejection at the Ohio supreme court either (worth ~\$0.05 for 2H impact in 2016).** In this sense, we see 2Q as remaining relatively lower key. We emphasize revisions appear for once generally positive

1Q results will maintain headwinds seen with lower guidance

Figure 209: 2Q16E YoY EPS

AES Earnings Walk	EPS
2Q15A Adjusted EPS	\$0.25
Hydrology	0.00
Planned Outages - Argentina, etc	(0.05)
Reversal of Eletropaulo - Booked contingency on cable	(0.03)
F/X & Commodities MtM	(0.04)
Capital Allocation - Debt Paydown	0.01
Capital Allocation - Equity Buyback	0.02
Asset Sales - Jordan CCGT, etc	0.01
Tax Rate - Was 50% in 1Q16	(0.01)
2Q16E Adjusted EPS UBS	\$0.15
2Q16E Consensus	\$0.17
2016E UBS	1.05
2016E Consensus	0.99
2016 Guidance	0.95-1.05

Source: Company data, Thomson Reuters, UBS estimates

What are the Key Issues for the Call?

- **Brazil: Both pending and further divestment.** Further divestment following media headlines of a potential sale and subsequent rebuttal. Additionally, growing confidence on macro condition in the country appears to be driving the equity of late.
- **Ohio:** How can DPL follow the FirstEnergy tune to get a similar deal in their pending ESP. Further, strategy on how to deal with the Supreme Court rejection of the existing construct is key as well.

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

[6/24/2016: Getting Dinged In Dayton](#)

[6/16/2016: Saying Sul-long Brazil!](#)

[5/31/2016: What to Make of the Recovery?](#)

[2/29/2016: Doing the Debt Walk](#)

[2/24/2016: Feeling the Full Force of Forex](#)

[12/22/2015: Another Embattled IPP](#)

[11/6/15: Feeling the Global Squeeze](#)

[9/8/15: Positioning for a Turnaround](#)

Finding a Less Turbulent Path (July 14th)

Brazil: Exiting the Volatility with strategic purpose as reducing F/X correlation

We held our latest NDR with AES mgmt this week in Europe. The most important focus remains a de-emphasis of Brazilian utilities, largely affirming a divestment strategy remains a key priority. With Brazil being the key EM country tied to shares, we believe a sale of the bulk of its consolidated exposure should meaningfully de-risk shares at least from a volatility perspective.

Growth areas are focused on two key areas – Gas and Batteries

In an effort to diversify away from coal (for which it receives increasing relative scrutiny), mgmt appears to have at least two over-arching growth strategies: the first is around an LNG driven gas strategy in Central and North America as well as a focus on battery deployments of all flavors. The final driver of growth remains the tailwind of macro factors such as F/X and commodities.

Asset sales – focused on reducing complexity and risk to boost multiple

Divestments remain focused on reducing risk in Europe and Asia, while also reducing balance complexity as few investors adequately understand the complexity of their various subsidiaries, including those that are consolidated (Eletropaulo) and those that have negligible equity value (DPL). The underlying strategic focus remains on reducing risk and growing the dividend to more align with traditional utilities. Further, a focus on peers remains a complementary effort, as efforts remain underway to tie its story more closely to the large diversified European utilities rather than heavily regulated US peers.

What do we think of shares?

We see further outperformance as tied principally to multiple expansion in LatAm as well as estimate revisions arising out of F/X improvement in Brazil. We see 2Q results as having a limited net macro impact on results despite the Latam backdrop. Despite a positive macro backdrop, we don't see a clear path towards further multiple improvement notwithstanding improvement across the wider Latam backdrop. Our price target is based on a sum-of-the-parts analysis.

What are our estimates?

Our estimates are largely unchanged vs. prior. We continue to assume our estimates the higher end of the 12-16% growth range through 2018. We emphasize a key question is the degree of slowing into 2019 YoY – with this the predominant focus with 4Q16 results as investors ask for more of a 'normalized' view of growth adjusted for the 'catchup' in the macro that drives at least 5% of the near-year bump (equity checks driving above-average growth prior to the big step-up in DPS growth also account for the near-term growth). We see a potential for continued outperformance in the event all projects reach in-service as desired in the ~2018 period.

Figure 210: AES EPS estimates

	2015A	2016E	2017E	2018E	2019E
UBS EPS estimates	1.22	1.05	1.16	1.36	1.56
EPS Growth	-6.1%	-14.3%	10.6%	17.6%	14.5%
Guidance (Low)		0.95	1.12	1.25	
Guidance (High)		1.05	1.16	1.35	

Source: Company Filings, FactSet, and UBS Estimates

Our full valuation

We reflect market multiples for the businesses below off the latest US P/E multiples of regulated utilities and IPPs.

Figure 211: SOP View for AES – Part I

Sum of the Parts Analysis - Hedged Analysis - UBSe								
Latin America Listed Subsidiaries						Low	Base	High
	AES Tiete (Common, GETI3)	AES Tiete (Pfd, GETI4)	AES Eletropaulo (Common, Pfd, ELPL4)	AES Eletropaulo (Pfd, ELPL4)	AES Gener			
UBS Price Target	20.00	20.00	7.26	8.00				
Current Share Price	13.20	14.55	6.16	6.79	319.67			
% Upside	52%	37%	18%	18%				
Ownership %	32.96%	14.94%	35.95%	3.41%	67.00%			
Shares O/S	197	184	67	101	8,070			
F/X Rate	3.61	3.61	3.61	3.61	688.20			
Market Value Stake	238	111	41	6	2,512		2,907	
UBS-Implied Equity Stake	360	152	48	8	2,512		3,079	
Premium PN/ON	10%		10%		Brazil		568	0.86189021
Shares Outstanding				reduce o		659	659	659
Implied Equity Value of Foreign Listed Subsidiaries (per Share)						4.67	4.67	4.67
AES Gener						\$3.81	\$3.81	\$3.81
AES Tiete						\$0.78	\$0.78	\$0.78
AES Eletropaulo						\$0.08	\$0.08	\$0.08
Latin American Utilities						Enterprise Value		
	2016 EBITDA	EV/EBITDA Multiple				Low	Base	High
Sul	0	0.0x	0.0x	0.0x		-	-	-
El Salvador	76	5.0x	6.0x	7.0x		378	453	529
Total LatAm Utilities (Non-Listed) EV	76	5.0x	6.0x	7.0x		378	453	529
Net Debt								
Sul - Equity Infusion Pending Sale of Company							75	
El Salvador							(239)	
Total LatAm Utilities Equity Value						214	289	365
Shares Outstanding						659	659	659
Total LatAm Utility Value Per Share (Non-Listed)						\$0.32	\$0.44	\$0.55
Sul						\$0.11	\$0.11	\$0.11
El Salvador						\$0.00	\$0.33	\$0.44
Latin American Generation						Enterprise Value		
	2016 EBITDA	EV/EBITDA Multiple				Low	Base	High
Private Subsidiaries								
Uruguaiana CCGT	1	5.0x	6.0x	7.0x		7	9	10
Argentina Generation Portfolio	176	5.0x	6.0x	7.0x		879	1,055	1,231
Panama Generation Portfolio (AES Interest)	181	5.0x	6.0x	7.0x		907	1,089	1,270
Panama CCGT Expansion (Equity Investment)							250	
Dominican Republic Portfolio	162	5.0x	6.0x	7.0x		808	969	1,131
Total LatAm Generation (Non-Listed) EV	520	5.0x	6.5x	7.0x		2,601	3,372	3,642
Net Debt								
Argentina Generation Portfolio							(201)	
Panama Generation Portfolio							(543)	
Dominican Republic Portfolio							(329)	
Total LatAm Generation Equity Value						1,529	2,299	2,569
Shares Outstanding						659	659	659
Total LatAm Generation Value Per Share (Non-Listed)						\$2.32	\$3.49	\$3.90
Uruguaiana CCGT						\$0.01	\$0.01	\$0.02
AES Argentina						\$1.03	\$1.30	\$1.56
AES Panama						\$0.55	\$1.21	\$1.10
AES Dominican Republic						\$0.73	\$0.97	\$1.22

Source: Company Filings, FactSet, and UBS Estimates

Figure 212: SOP View for AES – Part II

North American Utilities					Enterprise Value		
DPL	2017 Net Income		P/E Multiple		Low	Base	High
T&D Utility	68	17.5x	18.5x	19.5x	1,194	1,263	1,331
	Peer Multiple =		19.0x				
	Premium/Discount =		-0.5x				
Add: Back Hypothetical Debt					650	650	650
T&D Utility EV					1,844	1,913	1,981
	2016 EBITDA (Gen)						
Generation (excludes ESP uplift)	23	6.0x	7.0x	8.0x	136	159	181
DPL-ER	24	4.0x	5.0x	6.0x	96	120	144
Merchant EV					232	279	325
ESP Rates (Nonby passable, NPV) - Estimated Contribution @ 50% Prob					87	87	87
Total DPL Debt (DP&L and Inc.)					(1,922)	(1,922)	(1,922)
DPL Equity Value					241	356	471
	2017 Net Income		P/E Multiple				
IPL (Indianapolis Power & Light)	117	18.5x	19.0x	20.0x	2,163	2,221	2,338
	Peer Multiple =		19.0x				
	Premium/Discount =		0.0x				
IPALCO Ownership post-Selldown					70%	70%	70%
AES' Equity Value in IPL					\$1,514	\$1,555	\$1,637
Total US Utility Equity Value					\$1,514	\$1,555	\$1,637
Shares Outstanding					659	659	659
Total US Utility Value Per Share					\$2.30	\$2.36	\$2.48
DP&L (Dayton Power & Light)					\$0.37	\$0.54	\$0.71
IPL (Indianapolis Power & Light)					\$2.30	\$2.36	\$2.48

Source: Company Filings, FactSet, and UBS Estimates

Figure 213: SOP View for AES – Part III

<u>European Generation</u>	2016 EBITDA	EV/EBITDA Multiple			Low	Base	High
Private Subsidiaries							
AES Bulgaria (Maritza Lignite Plant)	213	4.0x	5.0x	6.0x	850	1,063	1,275
Kazakhstan	61	6.0x	7.0x	8.0x	366	427	488
UK Gen (Ballylumford CCGT and Kilroot Coal)	43	6.0x	7.0x	8.0x	256	299	342
Jordan (CCGT)	28	5.0x	6.0x	7.0x	139	166	194
Total European Generation EV	349	4.7x	5.7x	6.7x	1,642	1,991	2,340
Net Debt							
AES Bulgaria (Maritza Lignite Plant)						(589)	
AES Hungary (Tisza II Plant)						-	
Kazakhstan						(29)	
UK Generation (Ballylumford CCGT and Kilroot Coal)						(1)	
Jordan (CCGT)						(372)	
Total Net Debt						(1,151)	
Total European Generation Equity Value					614	964	1,313
Shares Outstanding					659	659	659
Total European Generation Value Per Share (Non-Listed)					\$0.93	\$1.46	\$1.99
AES Bulgaria (Maritza Lignite Plant)					\$0.40	\$0.72	\$1.04
AES Hungary (Tisza II Plant)					\$0.00	\$0.00	\$0.00
Kazakhstan					\$0.51	\$0.60	\$0.70
UK Generation (Ballylumford CCGT and Kilroot Coal)					\$0.39	\$0.45	\$0.52
Jordan (CCGT)					-\$0.35	-\$0.31	-\$0.27
<u>Asian Generation</u>	2016 EBITDA	EV/EBITDA Multiple			Low	Base	High
Private Subsidiaries							
Philippines (Masinloc), 51% Interest	55	6.0x	7.0x	8.0x	331	386	441
Masinloc Expansion (Equity Investment)						150	
Vietnam (Mong Duong), in-service	137	7.0x	7.0x	7.0x	961	961	961
Sri Lanka (Kelantissa)	27	6.0x	7.0x	8.0x	161	187	214
Total Asian Generation EV	219	6.6x	7.7x	7.4x	1,453	1,684	1,616
Net Debt							
Philippines (Masinloc), 51% Interest						(204)	
Vietnam (Mong Duong), In-service in 2016 - \$809Mn 51% owned						(646)	
Sri Lanka (Kelantissa)						-	
Total Net Debt						(850)	
Total Asian Generation Equity Value					602	834	766
Shares Outstanding					659	659	659
Total Asian Generation Value Per Share (Non-Listed)					\$0.91	\$1.27	\$1.16
Philippines (Masinloc)					\$0.19	\$0.50	\$0.36
Vietnam (Mong Duong), in-service in 2016					\$0.48	\$0.48	\$0.48
Sri Lanka (Kelantissa)					\$0.24	\$0.28	\$0.33

Source: Company Filings, FactSet, and UBS Estimates

Figure 214: SOP View for AES – Part IV

North American Generation	2016 EBITDA	EV/EBITDA Multiple			Low	Base	High
Southland (Contracted Gas in CA) - Re-contracte	119	6.0x	7.0x	8.0x	711	830	949
Mountainview	5	6.0x	7.0x	8.0x	30	35	40
Warrior Run (Contracted Coal in MD): Thru 2030	66	6.0x	7.0x	8.0x	398	464	530
Shady Point (Contracted Coal in OK)	27	6.0x	7.0x	8.0x	162	189	216
Hawaii (Contracted Coal in HI)	47	5.0x	6.0x	7.0x	235	282	329
Puerto Rico (Contracted Coal in PR)	148	5.0x	6.0x	7.0x	740	887	1,035
Merida (Contracted CCGT in Mexico)	37	6.0x	7.0x	8.0x	222	259	296
TEG/TEP (Contracted Coal in Mexico)	77	6.0x	7.0x	8.0x	465	542	620
Total North American Generation EV	526	5.6x	6.6x	7.6x	2,963	3,489	4,015
Net Debt							
Southland						(152)	
Warrior Run						(103)	
Shady Point						(39)	
Hawaii						(232)	
Puerto Rico						(446)	
TEG/TEP						(300)	
Total Net Debt						(1,272)	
Total North American Generation Equity Value					1,691	2,218	2,744
Shares Outstanding					659	659	659
Total North American Generation Value Per Share (Non-Listed)					\$2.57	\$3.37	\$4.16
Southland					\$0.85	\$1.03	\$1.21
Warrior Run					\$0.45	\$0.55	\$0.65
Deepwater					\$0.00	\$0.00	\$0.00
Red Oak					\$0.00	\$0.00	\$0.00
Ironwood					\$0.00	\$0.00	\$0.00
Shady Point					\$0.19	\$0.23	\$0.27
Hawaii					\$0.00	\$0.08	\$0.15
Beaver Valley					\$0.00	\$0.00	\$0.00
Puerto Rico					\$0.45	\$0.67	\$0.89
TEG/TEP					\$0.25	\$0.37	\$0.49

Source: Company Filings, FactSet, and UBS Estimates

Figure 215: Summary SOP View for AES

Summary SOP Valuation for AES Corp		% Owned by AES			Low	Base	High
Listed Latin American Subsidiaries					\$4.67	\$4.67	\$4.67
Latin American Utilities (Unlisted)					\$0.11	\$0.44	\$0.55
Latin American Generation (Unlisted)					\$2.31	\$3.48	\$3.88
North American Utilities					\$2.30	\$2.36	\$2.48
North American Generation					\$2.18	\$2.92	\$3.65
Asian Generation					\$0.91	\$1.27	\$1.16
European Generation					\$0.94	\$1.46	\$1.98
Summary SOP Valuation for AES Corp					Low	Base	High
Total Subsidiaries Equity Value					\$13.43	\$16.60	\$18.40
Other Adjustments (Parent Debt, etc)							
Parent Adjustments, Debt, and Corp/Other						(3,764)	
Shares Outstanding						659	
Parent Debt Outstanding and Cost Drag per Share						(\$5.71)	
AES Corp Total Equity Value per Share					\$8	\$11	\$13
Parent Adjustments, Debt, Etc							
	2016 EBITDA	EV/EBITDA Multiple					
Corp/"Other" businesses (EBITDA)	65	6.0x	7.0x	8.0x	\$389	\$454	\$519
	2017 Net Income						
Equity Investments	35	7.0x	8.0x	9.0x	\$245	\$280	\$315
NPV of NOLs						\$238	
Other Non-Recourse Debt (Corp/Other)							
Other Wind Projects, Euro/African Utes, etc						(\$104)	
Recourse Debt (using latest reported 10K numbers)							
Unsecured Notes						(\$5,015)	
Less Current Maturities						\$0	
Secured Debt / Term Loans						\$0	
Total Recourse Debt						(\$5,015)	
Total Cash (incl. Subsidiaries), FY15						\$1,262	
Exclude Subsidiary Cash, FY15						(\$755)	
Net Debt (FY15)						(\$4,508)	
Parent FCF (mid point of guidance)						\$575	
Investment in Subsidiaries						-\$330	
Shareholder Dividends						-\$290	
Expected Share Buy back						-\$79	
Incremental Cash Generation FY15 to FY16						-\$124	
Parent Adjustments, Debt, and Corp/Other						(3,764)	
Shares Outstanding (2016e)						659	
Parent Debt Outstanding and Cost Drag						(\$5.71)	
AES Corp Total Equity Value per Share					\$8	\$11	\$13

Source: Company Filings, FactSet, and UBS Estimates

Brazil: Exiting the Volatility

Timing on the asset divestment is predicated on completion of the 2016 Tiete contract expiration, reducing the risk of bilateral renegotiation. Following the success of the Sul sale announcement around 1Q, mgmt would like to be decisive on any further divestment if it were to occur, referring to the Eletropaulo business; shares are traded publicly and mgmt rules out any sale via open market. Given the market value of \$75Mn (~\$0.10/sh in SOTP value) and its contribution of just \$0.01 in EPS, we believe a sale would appear an easy opportunity to de-correlate the equity (it consolidates the segment given operational control despite a 16%

stake). The mixed message remains tied to its commitment to re-lever its Tiete subsidiary to acquire more generation in the country. While nominal real exposure would still likely decrease by ~\$1Bn despite re-leveraging, questions about the companies underlying exposure to the Americas remain. Despite the de-emphasis on Brazilian F/X currency, we estimate at least ~40% of the company's equity value is tied to this region via both listed and unlisted subsidiaries.

DPL: Getting to a better place following FE's footsteps

We are increasingly confident in positive resolution of its pending petition before the PUCO for an extended ESP. The PUCO has repeatedly clarified its intention to ensure the financial health of the states' utilities to enable their continued corporate operations in-state as well as support the viability of their underlying asset base. Despite the recent rejection of DPL's existing ESP by the Ohio Supreme Court (and associated ~\$0.10/sh contribution to 2016, with a ~\$0.05 impact if ultimately unwound), we don't expect a guidance shift yet – nor should investors read meaningfully into the willingness of the PUCO to provide further assistance under its pending ESP for implementation in 2017.

Tiete: Looking to re-lever via non-Hydro assets still.

Prices have evolved substantially in recent months as hydrology has improved, despite still being below average, with prices of late towards 75Rs/MWh, from north of 150Rs/MWh. Mgmt remains confident it can execute on a re-leveraging of the business with its existing debt capacity of ~2Bn Rs. With declining interest costs, mgmt is particularly constructive on cheaper costs of financing. The emphasis has been away from hydro assets towards non-hydro fossil fuel fired and renewable assets, seemingly with a focus on acquisition. This is an important shift in strategy; and contrasts from previous comments in 2015 which focused on potentially expanding its existing hydro portfolio to adjacent systems to capture synergies. The volatility arising from recent year swings in hydrology appear to have become intolerable for AES Corp overall as it seeks to reduce its key variability. The key consideration in re-leveraging the company remains the added sensitivity to Brazilian Real for the equity.

Alto Maipo: Big Hydro Construction Underway albeit a tad behind

AES mgmt is confident the SIC (Central) Chilean market will remain intact despite construction challenges around the deep tunneling required. Based on AES' last quarterly call, the project delay amounts to 1Q, with the project being gradually put in-service from 2H18 through 1H19. The project includes 60-miles of mining through the mountains to enable adequate hydrological flows. Among large-projects, we continue to monitor timing related to the exact magnitude of 2018 and 2019 y/y growth.

DPL: Get Resolution First, then Look at Commodity Exposure?

The company had previously contemplated a sale of its DPL business, however, has so far held off given the need for clarity around its ESP. While it suffered a recent setback at the Ohio Supreme Court, we remain confident in an outcome supportive of the company from the PUCO. In the near term, we do *not* expect mgmt to reduce EPS guidance on the Supreme Court rejection– neither for the remaining 2016 EPS benefits pending clarification of the Court's implementation before the PUCO as well for potential benefits in 2017+ as this is a separate and distinct filing pending before the commission for subsequent relief, technically unrelated to the rejected ESP structure rejected by the Court. Rather, we would expect the PUCO and DPL to respond with a similar proposal as illustrated in PUCO

Staff's latest novel approach embedded in its testimony before the FirstEnergy case in recent weeks, in which a distribution modernization rider, requiring installation of smart meters, would act as the vehicle for additional revenues, funnelling these back to the parent.

Getting More Questions on Coal: What is the Strategy from here?

Investors remain quite concerned over its overall exposure unlike previous meetings: Among the more notable shifts in the focus for the equity has been greater focus on AES' coal portfolio, with ~40% on a MW basis. With an emphasis on pruning the lower quality assets of the portfolio, the asset divestment strategy would appear to drive a wider eventual trend; for instance, DPL, its largely zero-equity value subsidiary contains ~7% of total capacity (~2GW). Further, we believe many of the remaining coal assets, located in less ideal regulatory jurisdictions, may indeed be the first divestment targets as mgmt looks to continue to prune its underlying portfolio. Finally, mgmt states the latest two coal plants under development in the Philippines and India are the last two likely ever developed by the company.

Returns: "Bracketed by the I's"

Mgmt continues to see returns largely within a 10-20% ROE range, with an average of ~15% across its contemplated growth prospects. The focus remains on incremental projects and selling down incremental stakes to maximize its return. Financial partners appear to be the likely partnership, with 30-40% stakes in AES' projects. Mgmt remains keen it be the operator of future projects. This would appear to add 1-2% to overall earned ROEs.

AES: More California Solar projects, but that's it for now.

Mgmt continues to quietly grow its solar business, with ~\$40 Mn of equity investments in Californian solar in 2016 alone. We note its renewable efforts remain relatively low key following its wider divestment of these businesses earlier in Europe and China. While it appears the strategy to address its more coal heavy portfolio is a clear strategic necessity, underlying growth ambitions in renewables remain more modest, seeing its cost of capital as largely too high relative to many peers to compete for lower return projects. We note this project is an example of a litany of smaller growth projects underway at the company to contribute to 8-10% EPS growth contemplated in 2017 and 2018 off 2016 lows (just 5% of EPS growth is contemplated with cost cutting exercises and the wider macro backdrop).

Adapting Coal to the Modern Grid? Developing More Flexible Coal.

A strategic priority appears to improve the operational characteristics of its existing coal portfolio to adapt to growing intermittency across grids, globally. The effort would appear to complement efforts to deploy its battery technology across a greater geographic footprint. We look to learn more on steam turbine flexibility in coming quarters – and a consistent theme across a wider range of older fleets (both coal and nuclear) to deal with greater renewable dispatch.

Argentina: An Eventual Value Proposition?

With EPS today at ~\$0.07 under the existing price caps in Argentina, mgmt has been striking an increasingly confident tone on eventual lifting of such price caps. At a contribution of \$90 Mn in PTC, this would imply ~\$30/kW-year in PTC margin on its 3GW portfolio. While no specific timetable or increased profitability targets are contemplated, mgmt specifically points to the thin profitability of its hydro portfolio in particular.

Where is the Growth? Three Themes.

LNG and Gas Generation: A Major Americas Player

We look for management to stress this theme within its story all the more in coming quarters. Panama has a 10-year CCGT contract for 350 MW. The CCGT would use only ~1/4 of the total LNG terminal capacity, but ROEs would improve meaningfully (above 15% average targeted) via effective marketing to other local gas plants as well as principally ship bunkering through the Panamanian Canal. Cruise Lines would appear the focal point to 'green' their image and meet emission requirements for sailing to coastal waters of several countries. Total investment is \$900 Mn-\$1 Bn. The goal remains to limit commodity risk, albeit the key risk appears to be volumetric commitments. This latest Panamanian effort complements the meaningful footprint of its existing LNG import facility into the Dominican Republic. We estimate this segment produces EBITDA of ~\$100 Mn.

Overall, Central America and Mexico appear the most meaningful source of incremental project growth, all of which focuses on transitioning the region away from expensive diesel and other refined oil products for power generation (enabling aggregate cost reductions to consumers despite meaningful spend opportunity tied to bringing gas into the region). In terms of next data points, we look for tangible developments on new gas plants under its new partnership with Grupo Bal. While mgmt is indeed concerned over the level of competition exhibited in the Mexican market place thus far, it appears confident it can succeed in gas plant development (rather than for instance renewable assets).

Battery Storage:

Small wins continue, but still quite a modest piece of the story. Mgmt remains a leader in this market, with a focus on development to both its own sites as well as deployment for other utilities and IPPs. It has recently been awarded a 40MW ratebase storage project within its core IPALCO (Indianapolis) subsidiary. Mgmt indicates it has a variety of interests for similar deployments with adjacent utilities in which AES will develop and deploy its integration wrap around standard battery chemistries provided from manufacturers such as LG Chem. Mgmt is meaningfully more bullish on battery deployment across emerging markets than OECD countries, where existing reliability is typically much better. We look for the company to explore adjacent deployments at existing sites across various islands such as the Dominican Republic and Puerto Rico where reliability is clearly less than ideal.

Among the further questions in the battery business is whether AES will meaningfully pursue smaller-sized 'economic' C&I market in addition to focusing on utility-scale deployment opportunities for both T&D utilities as well as generation complements.

Bottom Line: While this business continues to show positive developments, its overall earnings to the company remain pennies overall. We believe AES will remain at the front-edge of storage deployment given its existing IT wrap; in this regard its battery effort resemble both self-development and an internal specialized E&C function.

Dividend Growth tied to Parent FCF Growth:

Looking to informally target a dividend policy of 45-50% of Parent FCF in the long term; the goal of at least 10% dividend growth through 2018 is consistent with

the at least 10% DPS growth. We note this pace of Parent FCF growth and in turn DPS growth will clearly moderate thereafter, albeit we look for a more formal target as the CAGR is rolled forward with 4Q results next February. Mgmt continues to target a further improvement in its credit quality towards IG-like metrics, desiring at least BB+ metrics in coming years. We think an improvement in underlying credit quality will also be driven by the continued pruning and de-risking of the portfolio. We note mgmt. continues to prefer contracted generation rather than utility operations, in contrast to many US peers, as it perceives less overall risk in single contracted generation assets rather than wider customer-facing utilities in emerging markets.

Where is the Portfolio Repositioning? Still Focused on Americas.

We expect the company to continue to execute on a repositioning in its portfolio towards the Americas, with a focus on growth in Central and North America. We would expect divestments to remain oriented towards Europe and Asia, consistent with recent sales. The one exception appears to be Brazil where historical correlations appear to have a disproportionate impact on shares.

How has the Real done?

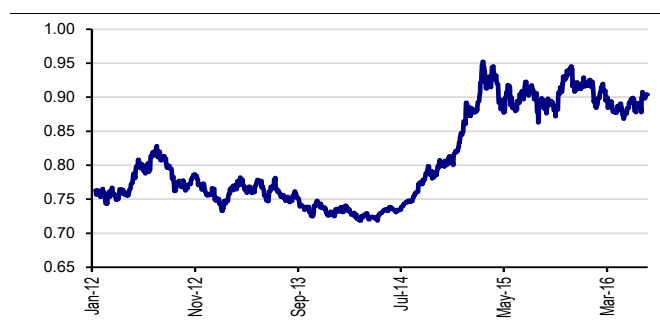
We emphasize the Brazilian currency appears to have found a bottom and fostered renewed confidence in the AES story. We perceive a positive shift in sentiment could well continue into 2Q results as a positive MtM on commodities and the macro backdrop remains an important opportunity. We flag the recovery in Brazilian currency relative to USD remains among the key improving factors.

Figure 216: F/X Rate for USD / Brazilian Real



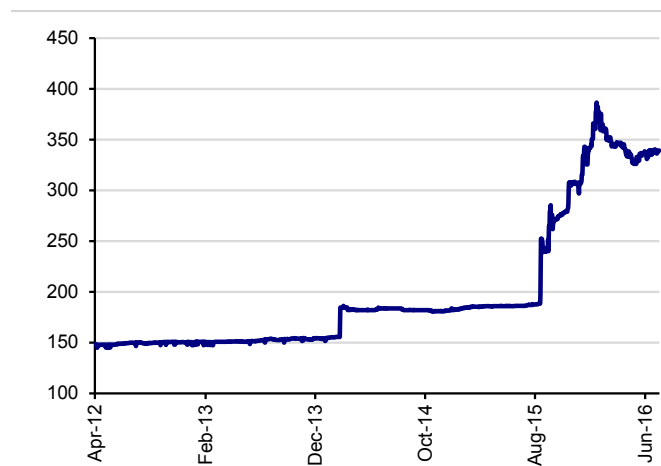
Source: FactSet

Figure 217: F/X Rate for USD / Euro



Source: FactSet

Figure 218: US Dollar per Kazakhstan Tenge



Source: Factset

Figure 219: US Dollar per GBP



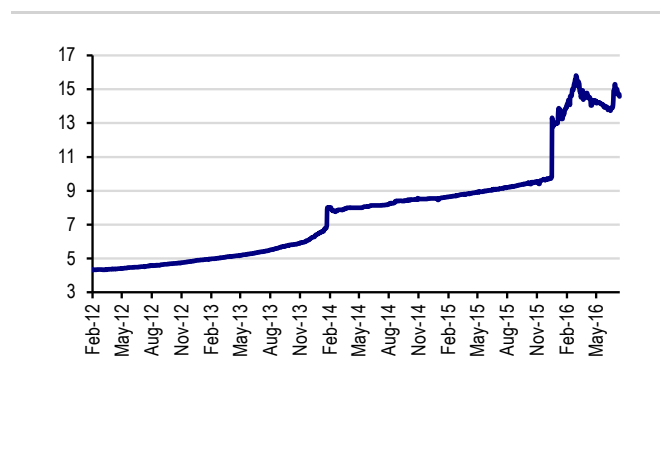
Source: Factset

Figure 220: US Dollar per Colombian Peso



Source: Factset

Figure 221: F/X Rate for USD / Argentine Peso



Source: Factset

But What's the Impact on the Quarter from Macro?

Despite the BRL recovery, the latest impact from the sharp move in the British Pound (via its Northern Ireland exposure) appears to be the primary headwind to shares. We emphasize the overall outlook appears to have improved modestly QoQ, a nice departure from prior consistent negative revisions.

Figure 222:F/X and Commodity Moves – since 1Q Call: Not much, but slightly *positive*!

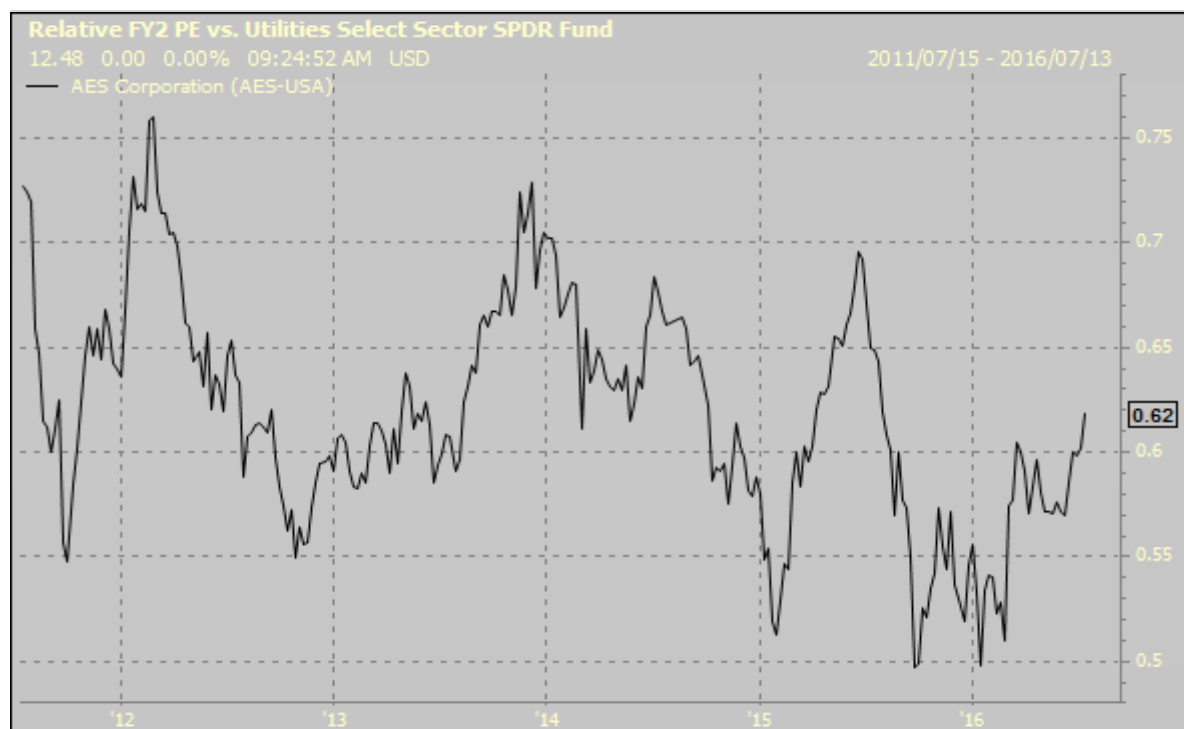
FX Exposure					Kazakhstan	Colombian	
	Argentine Peso	Brazilian Real	Euro	British Pound	Tenge	Peso	
Average Rate assumed for 2016							
as on 4/30/2016	15.43	3.56	0.87	0.68	341.10	2911.00	
Rate as on 7/12/2016	14.57	3.30	0.90	0.75	339.37	2918.71	
% change	-5.6%	-7.4%	3.9%	10.2%	-0.5%	0.3%	
Correlation	-ve	-ve	-ve	-ve	-ve	-ve	
Assumed sensitivity	0.005	0.005	0.005	0.005	0.005	0.005	
2016 EPS impact	0.0028	0.0037	-0.0020	-0.0051	0.0003	-0.0001	
2016 EPS Sensitivity	0.27%	0.36%	-0.19%	-0.49%	0.02%	-0.01%	
Commodity Exposure							
	NYMEX Coal	Rotterdam Coal	WTI Crude	Brent Crude	Henry Hub Nat Gas	UK NBP Nat Gas	PJM AD Hub
Average Rate assumed for 2016							
as on 4/30/2016	45	47	47	48	2.50	0.45	30
Rate as on 7/12/2016	39.5	57.7	46.8	48.5	2.7	0.5	32
% change	-12.2%	22.8%	-0.4%	1.0%	9.2%	-0.2%	5.3%
Weighting	52%	48%	25%	75%	75%	25%	100%
Correlation		-ve		+ve		+ve	+ve
Assumed sensitivity	0.010	0.010	0.005	0.005	0.005	0.005	0.025
2016 EPS impact		-0.0046		0.0003		0.0034	0.0132
2016 EPS Sensitivity		-0.44%		0.03%		0.33%	1.27%
Total MtM Impact to EPS							
	MtM currency impact	MtM commodity impact	Total New Impact (EPS)	Total New Impact (\$ Mn's)	% Change in EPS		
2016 EPS UBSe	-0.0005	0.0123	0.01	12	1.1%		

Source: Company Filings, FactSet, Bloomberg, UBS estimates

What we think of shares now?

Following the recent rally in shares, back to multi-year relative P/E highs vs. the XLU (still at a 38% discount on FY2 basis) and at a relatively strong historical P/E vs. AES' stand-alone multiple, the question is can the rally continue? We see potential for resolution in Ohio, and any further portfolio divestment (eg- Brazil) as boding well for the company through the balance of 2016. We emphasize from a fundamental perspective, shares appear to be exceeding recent historical multiples *even* when adjusting for recent improvement in US utility multiples (eg—its outpacing even the substantial recovery in utilities of late). Beyond its exposure to Latam, we attribute its recent outperformance to a supportive market backdrop to highly leveraged companies. We note few investors appear to appreciate the modest parent leverage, taking the company's EV on a consolidated basis (and in turn reflecting quite leveraged metrics.) This appears a misperception to the equity story. We note an emerging focus for mgmt. to simplify its capital structure as part of its ongoing asset pruning efforts.

Figure 223: AES 2 Yr Fwd P/E relative to XLU

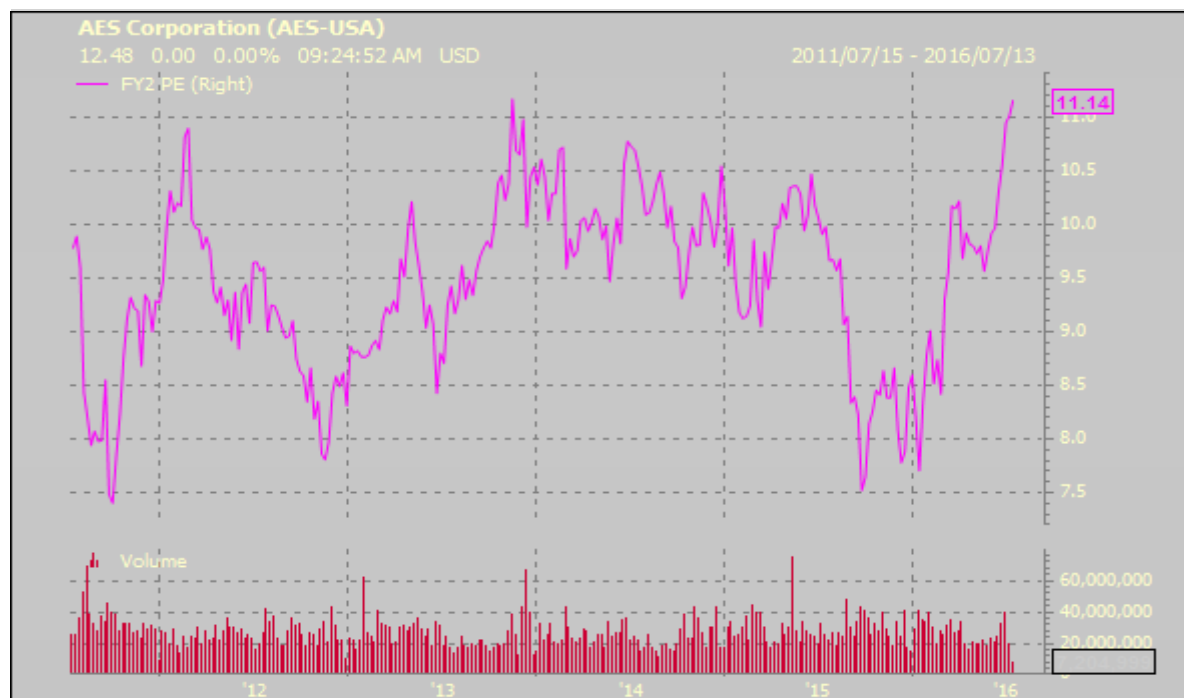


Source: FactSet

What about on an absolute basis? Multiple has improved dramatically.

We emphasize shares are now trading at a 5-years high

Figure 224: AES 2 Yr Fwd P/E

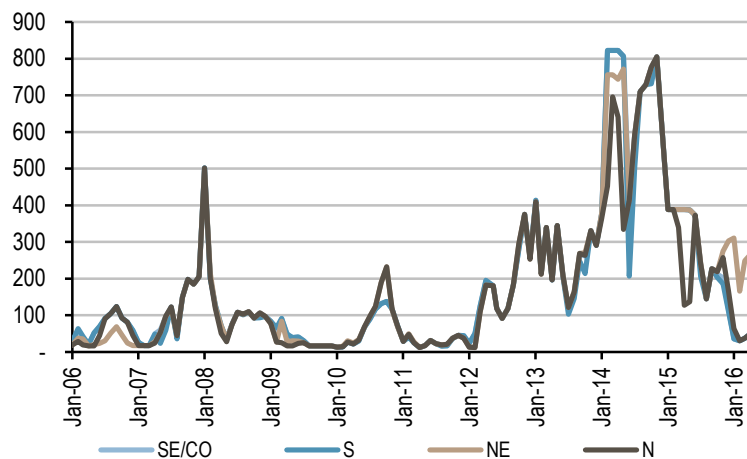


Source: FactSet

Brazil Prices Returning to Nominal Levels

We emphasize power prices have returned to modest levels. In contrast to the hydrological concerns of recent years, the latest prospects are concerning as ability to replace hedged power prices are challenged.

Figure 225: Brazilian spot market prices remain volatile (R\$/MWh, in real terms)

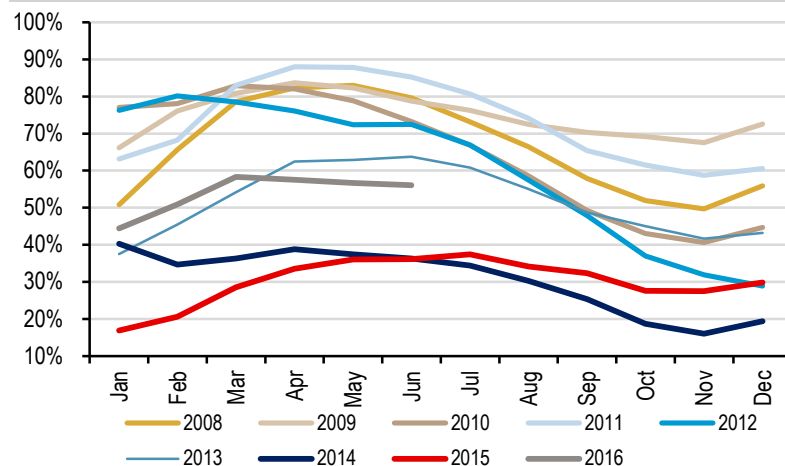


Source: CCEE, UBS

Hydrology Update

Reservoir levels today are better than one year ago but this is due to high level of dispatch of thermoelectricity plants.

Figure 226: Brazil hydrology: reservoir level data

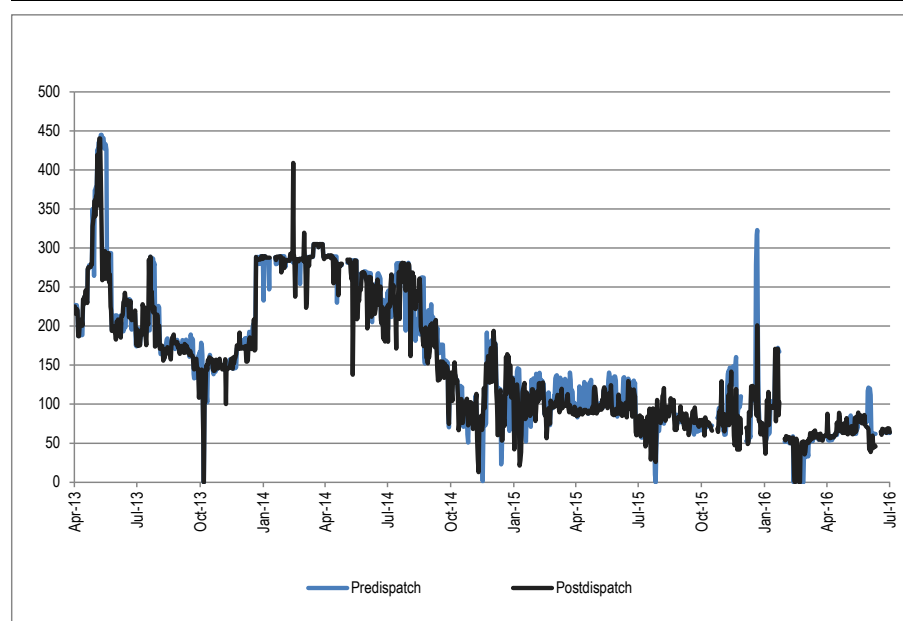


Source: ONS, UBS estimates

Panamanian Hydro Disclosures: Remains in Check

Following significant scrutiny in 2013 of hydro levels across Central America, we include recent spot prices following the significant drought conditions experienced recently. We emphasize AES' efforts in the country to add LNG capacity creates a more meaningful exposure to potential added demand should hydrological conditions soften in the future. They remain on track for the time being.

Figure 227: Panama Spot Prices – Pre/Post-Dispatch (Generation MWh per Unit System) – Back at the lows



Source: Company reports

Underlying International Commodity Performance

Following the rally in Rotterdam coal prices, we ask whether the arbitrage with US coal prices is sustainable. With bulk shipping rates among the lowest in 30-years at just ~\$6/t for this specific route per our UBS Shipping Analyst Spiro Dounis, this would appear to provide a clear potential for a demand pick up.

Figure 228: Rotterdam Coal (\$/ton), International Coal Proxy



Source: FactSet

Figure 229: NYMEX CAPP Coal (\$/ton), Domestic Coal Proxy



Source: FactSet

Comparing the Forward Gas Months: US vs. Europe

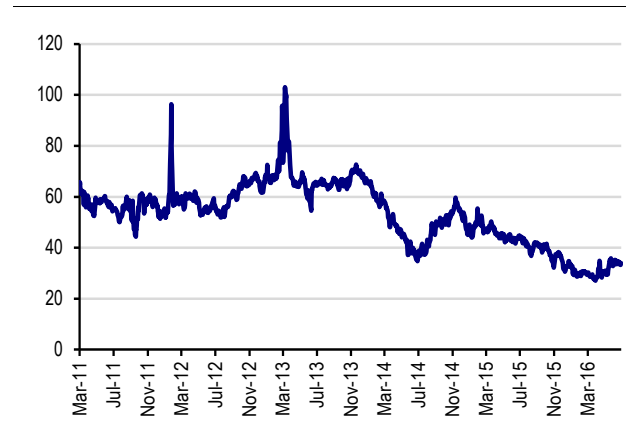
Henry Hub natural gas rose from August '13 lows of ~\$3.23/MMBtu to a high of ~\$6.15 on February 19th 2014. They have been declining steadily since then, however, 2Q16 observed reversal of gas prices and are trading ~ \$2.73 as of now; down -2.1% on Y-o-Y basis. Meanwhile, European gas prices have experienced decline of -24% on Y-o-Y. We see reversal of coal to gas switching at prices *at or above* \$4.50/MMBtu as meaningfully capping upside to gas demand over the intermediate term.

Figure 230: US Natural Gas (Hub), \$/MMBtu Front Month



Source: FactSet

Figure 231: European Natural Gas (NBP), pence/therm



Source: Bloomberg

Oil Prices: US vs. Europe

Meanwhile, domestic and international oil both appear to have found bottoms. Both WTI and Brent are trading at the sub \$50 level at the moment; and were down -18% and -3.8% respectively on Y-o-Y basis. We note here that according to management estimates for 2016, a 10% increase in WTI or Brent will result ~\$0.01 increase in 2016 EPS (note they are positively correlated).

Figure 232: Crude Oil (WTI), \$/Bbl



Source: FactSet

Figure 233: Crude Oil (IPE Brent), \$/Bbl



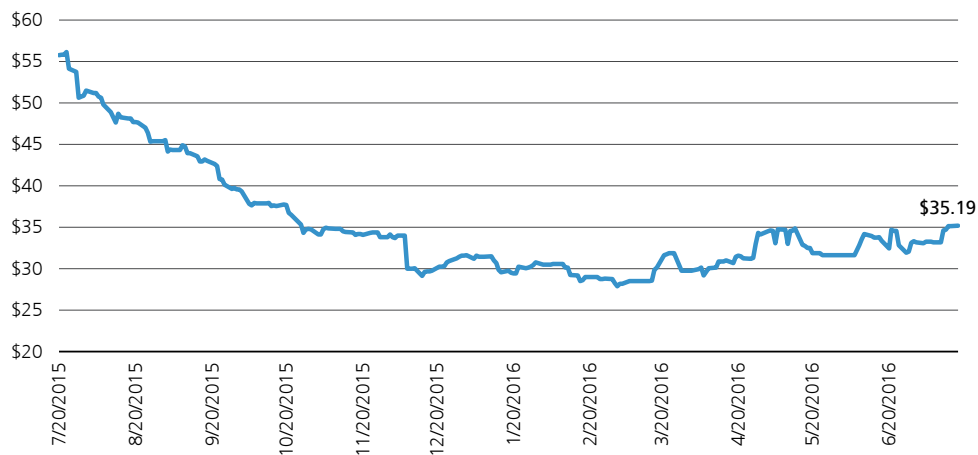
Source: FactSet

EFH (Unrated)

EFH Debt: Recovering with Gas

We include the latest quoted price for EFH 1st lien bank debt below; we see this as the most comparable entity to NRG equity in IPP landscape. We emphasize as the bankruptcy continues to edge towards plan confirmation, executives involved continue to express confidence on path towards eventual EFH restructuring re-emergence.

Figure 234: EFH Latest Bank Debt (Extended 2017 Term Loan): Recovering a Bit



Source: Bloomberg

EFH's initial post bankruptcy emergence paints a picture of substantial cost cuts

In its first public [presentation](#) of its outlook prior to emergence from bankruptcy, EFH painted an improved picture of its outlook, reflecting both existing but also prospective cost cuts to its SG&A cost structure to compete in the low power price environment in Texas. While clearly a constructive development to the company, we read this as a cautious datapoint for the wider potential for ERCOT recovery. Further, with a new mgmt set to take the helm, aspirations are for further cost cuts beyond those already reflected in the latest presentation. In particular further improvement in coal plant economics could be forthcoming as rail contracts and coal terms continue to reprice.

EFH disclosures also illustrate substantial profitability on Retail biz

Among the key positive surprises were meaningfully higher results on its TXU Energy business than previously projected. We perceive a wider concern in the ERCOT market that under-water generation assets are preserved through the extrinsic hedge they provide to highly profitable retail businesses, including TXU Energy and NRG. Disclosures are consistent with NRG in implying ~\$30/MWh+ resi margins when applying more modest ~\$5/MWh C&I margins; we continue to perceive meaningful risk tails to this business as migration from above-market contracts remains a meaningful risk to all incumbent electric retailers (for those who have yet to actively 'choose' to shop for their electric providers).

No discussion of legacy gas asset retirements either

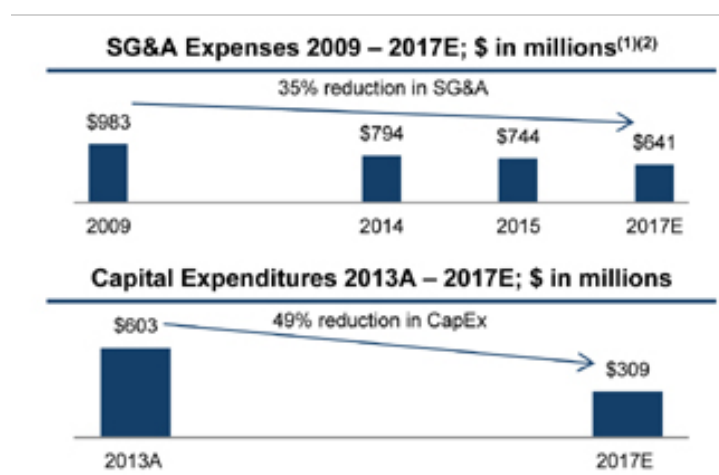
Notable within the focus on generation in the slides released is limited discussion of the legacy gas steamer portfolio. We continue to see this as a regional-wide question, particularly acute for both NRG and EFH around what to do with largely money losing steam-fired gas turbines. While ideal candidates for retirement, their large size and meaningful hedge characteristics despite 10+ hour ramp times, we have yet to see much by way of retirements of late. Rather, the single asset that attempted to retire was put back on an RMR emergency contract by ERCOT.

Cost Structure Plans are Below Expectations; No Structural Shutdowns in Sight

Current TCEH plan suggests SG&A expense can shift down substantially and has already moved from ~\$983M in 2009 to ~\$744M in 2015. Current plan suggests ~\$641M is achievable in 2017 – an incremental ~14% cost reduction in two years and even more ambitious in light of typical 2-3% wage inflation in the region. We view this as incremental confirmation that plant retirements are less likely imminently, further reinforced by ~50% capex cut from 2013A \$603M driven by conversion to "seasonal operations that lower run times leading to reduced maintenance and total variable costs".

TCEH's Cost structure appears to target substantial cost reductions but does NOT include assumptions around plant shutdowns

Figure 235: Corporate Cost Cutting: Not Plants



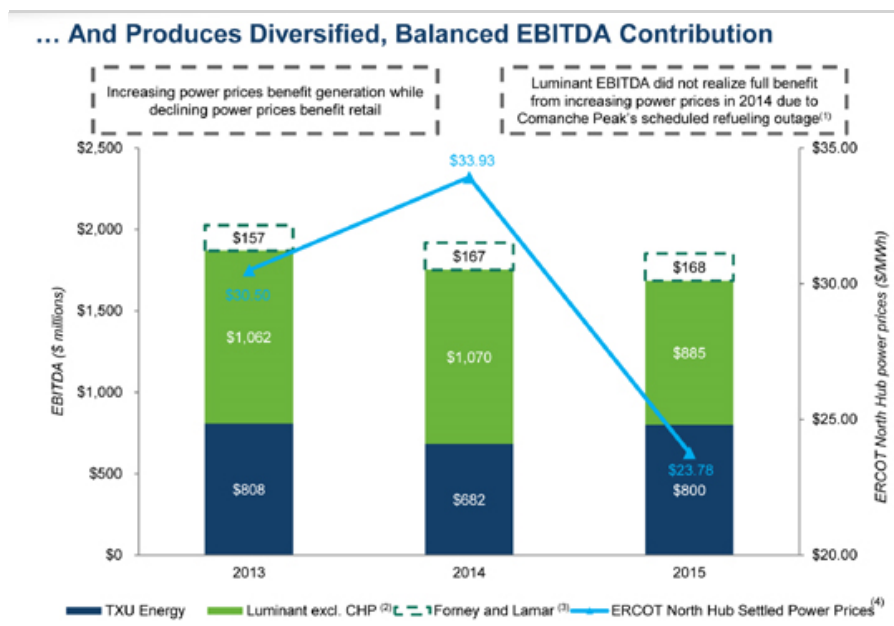
Source: Texas Competitive Electric Holdings Company July 12 Lender Presentation

Does a meaningful retail platform also limit retirement risk too?

In fact, balanced earnings stream appears to be a key focus for the new company – with TXU and Luminant complementing each other and providing insight into how the new company will function. Specifically, it appears management is most focused on maintaining diversification between retail and generation in order to act as a hedge against price spikes.

The wider question in the sector is just how much of a deficit are generators willing to take on via generation to support their highly lucrative retail operations? We read NRG's hesitancy to close plants in Texas as illustrative of this trend.

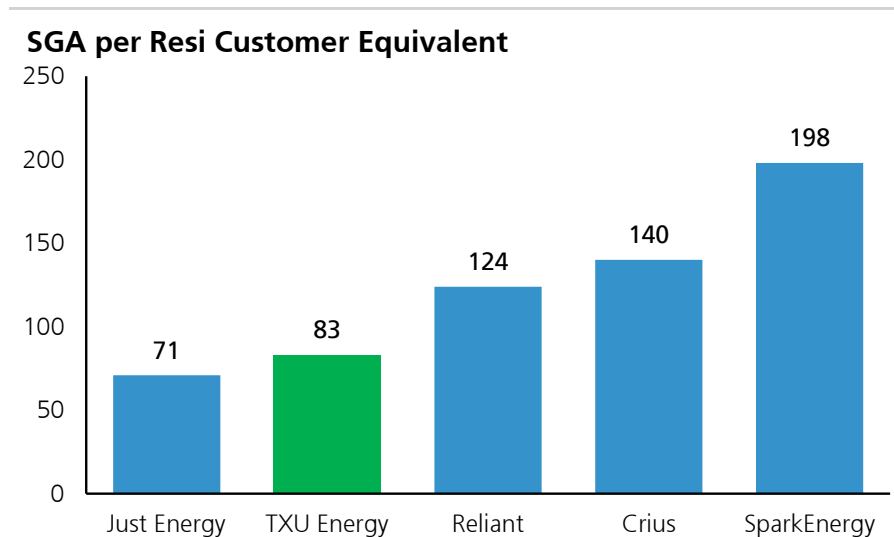
Figure 236: TCEH's focus on Diversified EBITDA Implies Value from Idle Plants



Retail Margins Also Appear Supportive of Keeping Even Old Plants as a Hedge

~25% market share for TXU Energy in the retail space suggests TXU's substantial retail exposure (the largest marketshare of any single provider according to management estimates) implies Luminant's existing generation fleet is more 'sticky' than some had previously thought.

Figure 237: SG&A per Residential Customer

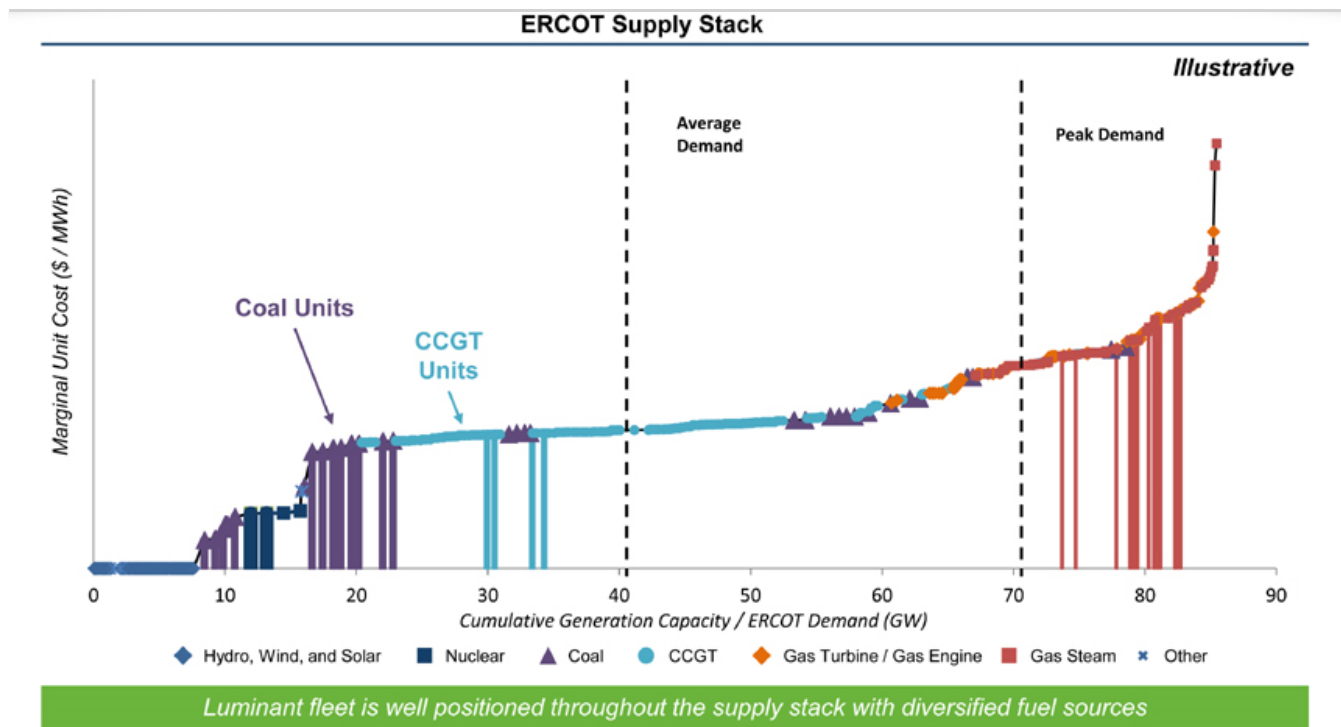


So What is the Generation Fleet? It's meaningful to ERCOT Mix

Luminant owns ~16,760MW of generation, or ~20% of total ERCOT generation base of ~87.4GW. This positions the company well ahead of NRG (10.6GW), Calpine (9.4GW), Dynegy (4.7GW), and Exelon (3.5GW) in ERCOT. Further, the company's recent acquisition of Forney and Lamar positions it in a somewhat more

diversified way throughout the supply stack in ERCOT, which could allow more economic plants to help float peakers to balance the retail side of the business. The presentation below appears to show its coal units as still being 'in the money' relative to gas plants (albeit a specific date is not provided for commodity curves here in the deck).

Figure 238: Management's Assumed Supply Curve



Source: Luminant analysis



10

Source: Texas Competitive Electric Holdings Company July 12 Lender Presentation

Retirements: The Three Oldest Plants Remain the Focus

While we note the company's newer units are actively operating, ~8 peakers are likely subsidized by the rest of the business. We have summarized the company's presentation below in a fleet overview. While Big Brown is the most concerning unit (with no scrubbers installed), the other plants appear to be a key part of the company's strategy exiting bankruptcy. Further scrutiny exists of the other old coal plants, Martin Lake and Monticello.

Figure 239: Luminant Portfolio

	Facility	Capacity	Capacity Fator (historic avg)	COD	Fuel	Tech
	Comanche Peak	2300	98%	1990/1993	Nuclear	
Seasonal	Big Brown	1150	77%	1971-72	Coal	ST
	Martin Lake	2250	66%	1977-79	Coal	ST
	Monticello	1880	39%	1974-78	Coal	ST
Newer Plants	Oak Grove	1600	87%	2010/2011	Coal	ST
	Shadow Unit 5	580	80%	2010	Coal	ST
	Forney	1912	54%	2003	Gas	CC
	Lamar	1076	60%	2000	Gas	CC
Simple Cycle and Peakers	Decordova	260	N/A	1990	Gas	CT
	Graham	630	N/A	1960/1969	Gas	ST
	Lake Hubbard	921	N/A	1970/1973	Gas	ST
	Morgan Creek	390	N/A	1988	Gas	CT
	Permian Basin	325	N/A	1988/1990	Gas	CT
	Stryker Creek	685	N/A	1958/1965	Gas	ST
	Trinidad	244	N/A	1965	Gas	ST
Total Nuclear		2,300				
Total Coal		7,460				
Total Nat Gas		6,443				

Source: Texas Competitive Electric Holdings Company July 12 Lender Presentation

What other units in Texas?

Besides EFH, we remain focused on both DYN's pending acquisition of Colleto Creek and whether this smaller unit will be retired as part of the acquisition as well as Blackstone's Twin Oaks plants, a smaller mine-mouth lignite coal facility. Both would appear to be near breakeven.

But what to make of the legacy steamers and peakers too?

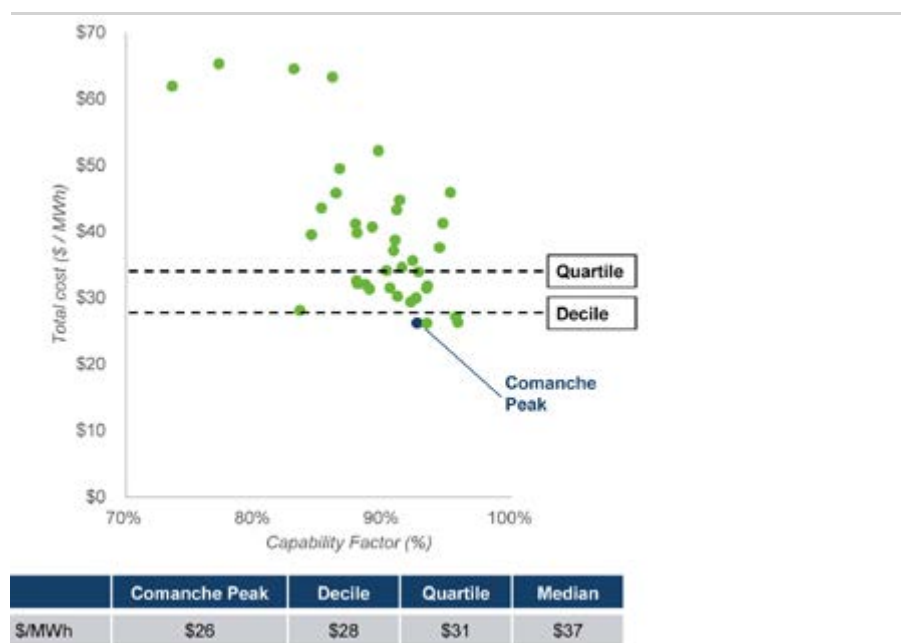
We emphasize most of the focus remains on the seasonally dispatched coal assets, but we see the less nimble peaking steam-fired gas units as also at risk given their long startup times are less ideal to garner scarcity pricing revenues. We emphasize that much of the existing fleet, particularly EFH's larger gas units are indeed for this vintage.

EFH's Comanche Peak Nuclear Plant isn't going anywhere either

Comanche Peak, the 2.3GW nuclear plant in mid-Texas built in the early 90s, is one of the lowest cost units in the country according to Luminant disclosures. As shown below, EUCG estimates ~\$26/MWh total cost for the Comanche Peak plant – well below ~40 other comparable units but more importantly providing an incremental datapoint suggesting prolonged structural weakness in power prices. Based on NEI disclosures the average US nuclear unit had an all-in cost of \$36/MWh in 2014 with first quartile units closer to \$29/MWh (making Comanche among the single lowest cost nuclear plants in the country).

Comanche Peak runs at an industry low \$26/MWh all-in cost

Figure 240: Benchmarking Luminant's Comanche Peak



Source: Texas Competitive Electric Holdings Company July 12 Lender Presentation. 18 month fuel cycle US Nukes, analyzing data from EUCG

Air Quality Regulations Still Coming.. Driving Decisions

The Flip Side: If Anything Might Retire, think Big Brown is a Candidate

We see the recent decision to shift towards 100% PRB fuel-sourcing for this plant as indicative of the plant's overall challenges, with the move to this fuel likely incrementally more expensive than its existing lignite sources, but a must as the resources at current mines are exhausted. We note the move to PRB also improves its MATS dispatch profile as well as likely benefits from improved rail delivery terms. While comparably sized, it is the only plant could be targeted by all three new air quality regulations; we emphasize timing on this shut down remains consistent with peers, suggesting a delay into 2017 on a decision point is possible should a stay on the Regional Haze be granted.

Big Brown does not currently have scrubbers.

It's really a question of *when* rather than *if* in our view.. ongoing legal wrangling could take another year however

Beyond just the meaningful compliance capex contemplated for Big Brown 1&2, Monticello 3 and Martin Lake 1-3 would have modest capex needs for Regional Haze compliance as well. Moreover, across the portfolio coal ash (CCR) compliance capex appears to be the primary driver of incremental environmental capex.

Digging into the legal pathways for the Regional Haze regulations

We emphasize the RH regulations could well evolve in a number of different pathways depending initially on which jurisdiction is adopted for the courts. We note historically the DC Circuit Court has largely upheld agency decisions on RH. All around, we note regulation implementation has proven largely successful in several high-profile examples in recent years including both OK and NM in recent years. Without a capacity market, TX will *not* see coal units converted to gas.

We caution those reading the chart below that high emissions on a trailing basis for SO₂ can be attributed to simply bypassing (not running) control technology; we suspect regulations like Regional Haze would effectively require their use and provide a substantial portion of the delta in compliance. It is really about how stringent the regulations are – and whether existing scrubbers can meet emissions rates below the (0.10lb/MMBtu level). Every increment is increasingly difficult.

[For our Full Latest Report on Texas Air Quality Regs please click here for the full report.](#)

Figure 241: Coal Power Plants Subject to Regional Haze Substantial Reductions Asked

Facility Name	County	Operator	Coal Type	MW Capacity	Scrubber?	RH Deadline	2014 SO ₂ Rate (lbs/MMBtu)	2014 NO _x Rate (lbs/MMBtu)	Final RH Rule Allowed Rate (lbs/MMBtu)	Reduction - based on rate (%)	Dallas Fort-Worth Exposure
Big Brown	Freestone	EFH	lignite	593	No	5 Years	1.499	0.1313	0.04	97.3	Yes
Big Brown	Freestone	EFH	lignite	593	No	5 Years	1.498	0.1331	0.04	97.3	Yes
Limestone	Limestone	NRG	lignite	893	Old	3 Years	0.472	0.2090	0.08	83.1	No
Limestone	Limestone	NRG	lignite	957	Old	3 Years	0.483	0.2090	0.08	83.4	No
Martin Lake	Rusk	EFH	lignite	793	Old	3 Years	0.739	0.1597	0.12	83.8	Yes
Martin Lake	Rusk	EFH	lignite	793	Old	3 Years	0.696	0.1598	0.12	82.8	Yes
Martin Lake	Rusk	EFH	lignite	793	Old	3 Years	0.726	0.1511	0.11	84.8	Yes
Monticello	Titus	EFH	lignite	593	No	5 Years	0.825	0.1265	0.04	95.2	Yes
Monticello	Titus	EFH	lignite	593	No	5 Years	0.815	0.1183	0.04	95.1	Yes
Monticello	Titus	EFH	lignite	793	Old	3 Years	0.362	0.1565	0.06	93.4	Yes
Sandow	Milam	EFH	lignite	591	Old	3 Years	0.930	0.0621	0.2	78.5	No
Coletto Creek	Goliad	DYN	PRB	600	No	5 Years	0.676	0.1306	0.04	94.1	No
Tolk Station	Lamb	XEL	PRB	568	No	5 Years	0.506	0.1361	0.06	88.1	No
Tolk Station	Lamb	XEL	PRB	568	No	5 Years	0.518	0.1475	0.06	88.4	No
San Miguel*	Atascosa	San M.	lignite	410	*	1 Year	0.519	0.1777	*	*	No

Source: EPA, SNL Energy, Sierra Club, and UBS Estimates, Company Filings

Further, NRG remains confident it has found cost effective solutions to ensure the Limestone unit is fully compliant with at least the Regional Haze regulations. While less tangible, we are also increasingly focused on whether further NO_x specific regulations will be imposed on the Dallas/Forth Worth area (beyond the largely SO₂ limitations required for the Regional Haze regulations for ERCOT overall).

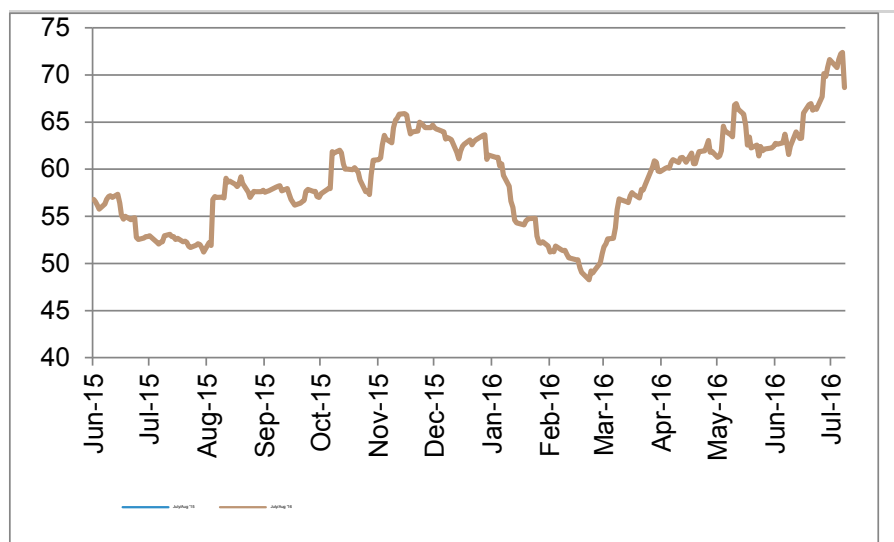
Summer-Time Concerns: Getting a bit Windy of Late?

Among the other growing themes in the market is the penetration of wind. We note recent above-average wind dispatch further calls into question expectations for the total potential wind dispatch into the market at seasonally peak periods, likely weighing on Summer peak price expectations (July/Aug). We emphasize last week wind in Texas claimed a new high water mark for mid-summer dispatch at ~23% of total market share during the hotter ERCOT day – this translates to a roughly ~low 70% capacity factor on the existing wind fleet during a heat wave (despite coincident historic peak expectations for wind during on-peak periods in the ~20% range).

Of late, the summer forwards have recovered to a multi-year high as the split between peak and off-peak has reached new disparities. The question is whether expectations for above-average weather and limited impact from renewables (wind) during peak times will enable this price formation. Overall, recent price trends of late remain quite supportive.

Be careful of wind dispatch limiting peak price formation during the summer

Figure 242: Summer July/Aug 2017 Curve for ERCOT Houston



Source: Platts

Updated Management Projections

We updated consolidated projections from management's most recent projections, in turn applying an adjustment for current power & gas curves; those from mgmt are provided as of 12/13/2015.

Figure 243: TCEH Mini Model

EFH Corp Mini-Model Projections using Mgmt Projections and Updating using MtM Commodities								
	2014	2015	2016	2017	2018	2019	2020	2021
TCEH Consolidated Adjusted EBITDA (from 2013/	2,296	1,722	1,520	1,315	1,327	1,397	1,517	1,733
<i>Subtract: TXU Energy (slide 20 actuals)</i>	882	800	784	768	753	738	723	709
Implied Generation (Luminant) EBITDA	1,414	922	736	547	574	659	794	1,024
Forney Lamar	167	168	110	157	164	162	160	175
Hedge Value (Disclosed) - 10/15/13 8K	(587)	0	0	0	0	0	0	0
Implied Open EBITDA Generation (Luminant) - includes F+I	2,168	1,090	846	703	739	821	954	1,200
Implied Open Generation GM	3,669	1,924	1,630	1,511	1,570	1,678	1,836	2,109
Expected Generation TWh (Mgmt Projection from	85.4	80.3	80.0	74.4	70.9	70.9	69.3	67.3
ERCOT-North (ATC), as of Dec 31, 2015	33.93	23.78	24.99	27.22	28.93	30.97	32.84	34.76
Houston Shipping Channel Gas as of Dec 31, 2015	4.33	2.57	2.46	2.79	2.91	3.03	3.10	3.18
<i>Implied Heat Rate</i>	<i>7.84</i>	<i>9.25</i>	<i>10.16</i>	<i>9.76</i>	<i>9.94</i>	<i>10.22</i>	<i>10.59</i>	<i>10.93</i>
Hedged TCEH EBITDA (MtM)	2,296	1,722	1,520	849	906	1,010	1,083	1,145
Implied All-in Fuel, O&M, SG&A Costs (\$/MWh)	27	27	26	26	27	27	28	28
Reflecting the Latest Commodity Shifts								
ERCOT-North (ATC) - MtM Improvement/(Declines), \$/MWh			(0.85)	2.76	0.80	(0.98)	(2.85)	(4.77)
Volumes	<u>85.39</u>	<u>80.33</u>	<u>80.03</u>	<u>74.41</u>	<u>70.86</u>	<u>70.87</u>	<u>69.34</u>	<u>67.28</u>
Change in Hedge Value since Dec 31, 2015	-	-	(68)	205	56	(69)	(198)	(321)
Hedged TCEH EBITDA (Mgmt Projections), using latest N	2,296	1,722	1,452	1,520	1,383	1,328	1,319	1,412
Unlevered FCF Build								
EBITDA - MtM			1,452	1,520	1,383	1,328	1,319	1,412
Capex (Inc Nuclear Fuel) (Mgmt Assumptions)			(384)	(309)	(387)	(335)	(330)	(387)
Working Capital (Mgmt Assumptions)			(123)	70	8	(16)	(16)	(22)
Taxes (Mgmt Assumptions)			(24)	(65)	(15)	16	(17)	(115)
Tax Receivable Agreement Pmts (Mgmt Assumptions)			-	-	(78)	(104)	(90)	(180)
Other (Mgmt Assumptions)			(209)	(28)	(39)	(41)	(41)	(65)
Unlevered FCF (MtM)			712	1,188	872	848	825	643

Source: Company Filings, UBSe reflects adjustment in commodity viewprice using known Platts power price shifts

Southern Company

Lifting Price Target with Group P/E Expansion

Southern under regulatory scrutiny on the Kemper project grows

On July 5th the New York Times published an article focusing on Southern Company, specifically its Plant Ratcliffe (Kemper County) Integrated Coal Gasification Combined Cycle (IGCC) project. The report includes statements made by a former engineer at the plant who was, per the OSHA, wrongfully terminated by SO. The employee has alleged that the public disclosures about the construction were inaccurate and misleading. Southern has responded to the report saying that it investigated claims and the article has a "pre-determined objective and tone". We believe that the latest high-profile allegations in addition to the SEC investigation will further raise regulatory scrutiny of the project.

Timing of the Mississippi rate case will be the next key issue

We look for further clarity on exactly when management will declare in-service and file the associated rate case with the Mississippi Public Service Commission (PSC) given the significant monthly costs associated with the plant. Management has indicated that despite a targeted in-service date of August 2016, the associated rate case filing could be made approximately 3-5 months following formal in-service.

Georgia PSC Staff views project schedule as "extremely challenging"

The leaders of the Georgia Public Service (PSC) Staff oversight of Vogtle 3 & 4 (Independent Construction Monitor; ICM) indicated that it sees a high probability that Southern will not be able to achieve the in-service data for Units 3 (June 2019) and 4 (June 2020) in its testimony from June 17th. Production for January – May 2016 has not been achieved per the ICM and it does not believe that the assumption of future mitigation is supported

Valuation: Increase PT to \$51 (from \$45) due to peer multiple expansion

Our valuation is based on a 2018E sum-of-the-parts analysis. The increase in our price target is driven by the expansion of the regulated utility peer group P/E to 17.7x from ~16x previously. We continue to apply significant discounts to the subsidiaries with elevated regulatory and execution risks (Vogtle and Kemper).

Equities

Americas

Electric Utilities

12-month rating

Sell

12m price target

US\$51.00
Prior: US\$45.00

Price

US\$53.62
RIC: SO.N **BBG:** SO US

Trading data and key metrics

52-wk range US\$54.44-41.98

Market cap. US\$48.7bn

Shares o/s 908m (COM)

Free float 99%

Avg. daily volume ('000) 1,752

Avg. daily value (m) US\$89.3

Common s/h equity (12/16E) US\$22.5bn

P/BV (12/16E) 2.2x

Net debt / EBITDA (12/16E) 4.3x

EPS (UBS, diluted) (US\$)

	12/16E			
	From	To	% ch	Cons.
Q1	0.58	0.58	0	0.58
Q2E	0.71	0.72	2	0.69
Q3E	1.13	1.13	NM	1.11
Q4E	0.42	0.41	-3	0.49
12/16E	2.83	2.83	0	2.84
12/17E	2.85	2.85	0	2.97
12/18E	2.97	2.97	0	3.08

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Highlights (US\$m)	12/13	12/14	12/15	12/16E	12/17E	12/18E	12/19E	12/20E
Revenues	17,087	18,499	17,527	18,203	18,708	19,248	19,801	20,451
EBIT (UBS)	4,552	4,743	4,834	5,142	5,366	5,617	5,893	6,081
Net earnings (UBS)	2,377	2,516	2,628	2,626	2,688	2,802	2,901	2,979
EPS (UBS, diluted) (US\$)	2.71	2.80	2.89	2.83	2.85	2.97	3.08	3.16
DPS (US\$)	2.01	2.08	2.15	2.22	2.29	2.36	2.43	2.50
Net (debt) / cash	(22,636)	(25,558)	(27,377)	(32,285)	(33,180)	(34,105)	(34,383)	(34,486)
Profitability/valuation	12/13	12/14	12/15	12/16E	12/17E	12/18E	12/19E	12/20E
EBIT margin %	26.6	25.6	27.6	28.2	28.7	29.2	29.8	29.7
ROIC (EBIT) %	12.7	12.6	12.1	11.7	11.3	11.5	11.7	11.9
EV/EBITDA (core) x	9.7	9.9	10.2	9.4	9.4	8.9	8.5	8.2
P/E (UBS, diluted) x	16.1	15.8	15.6	18.9	18.8	18.0	17.4	17.0
Equity FCF (UBS) yield %	0.6	(0.6)	(3.3)	(6.2)	2.2	2.2	3.7	4.2
Net dividend yield %	4.6	4.7	4.8	4.1	4.3	4.4	4.5	4.7

Source: Company accounts, Thomson Reuters, UBS estimates. Metrics marked as (UBS) have had analyst adjustments applied. Valuations: based on an average share price that year, (E): based on a share price of US\$53.62 on 19 Jul 2016 18:43 EDT

Southern Company Investment case

Southern has underperformed YTD and now investor attention is on the latest with Kemper and Vogtle construction. We believe that Southern deserves a discount given these material construction risks and questions about timing and magnitude of the associated rate recovery. Most recently in Georgia the independent project monitor has cautioned that the latest timeline does not appear to be supported.

Valuation Method and Risk Statement

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 Integrations. 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

Solar sector risks include : 1) Solar panel and other input pricing is subject to ongoing price deflation, which affects economics of downstream projects and margins of upstream producers. 2) Government incentives being added or removed have had a disproportionate effect on demand in the past, and may continue to 3) reliance on power purchase agreements in electricity markets could make future contracts more difficult to sign 4) solar power is directly competing with other traditional generators as well as other renewables like wind, which creates uncertainty as wholesale power markets shift 5) Headline risk and policy risk continue to shift economics in countries as trade policies and changes to other key policies affect solar economics.

Valuation for IPPs are based on sum-of-the-parts analysis.

Valuations for regulated utilities are based on multiples of earnings per share.

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12-Month Rating	Definition	Coverage ¹	IB Services ²
Buy	FSR is > 6% above the MRA.	47%	32%
Neutral	FSR is between -6% and 6% of the MRA.	38%	25%
Sell	FSR is > 6% below the MRA.	15%	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.	<1%	<1%
Sell	Stock price expected to fall within three months from the time the rating was assigned because of a specific catalyst or event.	<1%	<1%

Source: UBS. Rating allocations are as of 30 June 2016.

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.

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UBS Securities LLC: Julien Dumoulin-Smith; Paul Zimbardo; Jeremiah Booream, CFA.

Company Disclosures

Company Name	Reuters	12-month rating	Short-term rating	Price	Price date
AES Corporation ¹⁶	AES.N	Neutral	N/A	US\$12.59	21 Jul 2016
Ameren Corp. ¹⁶	AEE.N	Neutral	N/A	US\$52.24	21 Jul 2016
American Electric Power, Inc. ^{5, 6a, 7, 16}	AEP.N	Buy	N/A	US\$69.43	21 Jul 2016
Avista Corp ^{4, 6c, 7, 16}	AVA.N	Sell	N/A	US\$43.68	21 Jul 2016
Calpine Corporation ^{4, 5, 6a, 7, 16}	CPN.N	Buy	N/A	US\$14.63	21 Jul 2016
CMS Energy Corporation ¹⁶	CMS.N	Neutral	N/A	US\$45.11	21 Jul 2016
Consolidated Edison ^{2, 4, 5, 6a, 16}	ED.N	Sell	N/A	US\$79.89	21 Jul 2016
Dominion Resources ^{2, 4, 5, 6a, 6b, 6c, 7, 16}	D.N	Neutral	N/A	US\$77.60	21 Jul 2016
DTE Energy Co. ^{2, 4, 5, 6a, 7, 16}	DTE.N	Buy	N/A	US\$98.36	21 Jul 2016
Duke Energy ^{2, 4, 5, 6a, 6c, 7, 16}	DUK.N	Buy	N/A	US\$85.40	21 Jul 2016
Dynegy, Inc. ^{6a, 7, 16}	DYN.N	Neutral	N/A	US\$16.42	21 Jul 2016
Edison International ^{7, 16}	EIX.N	Buy	N/A	US\$76.74	21 Jul 2016
Empire District Electric Company ^{16, 19}	EDE.N	Neutral (CBE)	N/A	US\$33.78	21 Jul 2016
Entergy Corp. ¹⁶	ETR.N	Sell	N/A	US\$80.23	21 Jul 2016
Eversource Energy ¹⁶	ES.N	Neutral	N/A	US\$58.01	21 Jul 2016
Exelon Corp. ^{6a, 7, 16}	EXC.N	Neutral	N/A	US\$36.46	21 Jul 2016
FirstEnergy Corp. ^{7, 16}	FE.N	Neutral	N/A	US\$35.96	21 Jul 2016
ITC Holdings Corp ^{16, 19}	ITC.N	Neutral (CBE)	N/A	US\$46.32	21 Jul 2016
NextEra Energy ^{2, 4, 5, 6a, 6c, 7, 16}	NEE.N	Buy	N/A	US\$128.26	21 Jul 2016
NRG Energy Inc. ^{7, 13, 16}	NRG.N	Sell	N/A	US\$14.57	21 Jul 2016
NRG Yield ¹⁶	NYLDA.N	Buy	N/A	US\$16.88	21 Jul 2016
PG&E Corporation ¹⁶	PCG.N	Neutral	N/A	US\$64.16	21 Jul 2016
Pinnacle West Capital Co. ^{6a, 16}	PNW.N	Neutral	N/A	US\$79.66	21 Jul 2016
Portland General Electric Company ¹⁶	POR.N	Buy	N/A	US\$44.38	21 Jul 2016
PPL Corporation ^{2, 4, 5, 6a, 6c, 7, 16}	PPL.N	Buy	N/A	US\$37.13	21 Jul 2016
Public Service Enterprise Group ¹⁶	PEG.N	Buy	N/A	US\$45.97	21 Jul 2016
SCANA Corp. ^{2, 4, 5, 6a, 7, 16}	SCG.N	Neutral	N/A	US\$74.14	21 Jul 2016
Sempra Energy ^{2, 4, 5, 6a, 6c, 7, 16, 18}	SRE.N	Buy	N/A	US\$113.06	21 Jul 2016
Southern Company ^{2, 4, 5, 6a, 6c, 7, 16}	SO.N	Sell	N/A	US\$53.90	21 Jul 2016
Talen Energy Corp ^{4, 5, 6a, 16}	TLN.N	Neutral	N/A	US\$13.66	21 Jul 2016
WEC Energy Group Inc. ¹⁶	WEC.N	Neutral	N/A	US\$64.72	21 Jul 2016
Westar Energy, Inc. ^{6a, 16}	WR.N	Neutral	N/A	US\$56.25	21 Jul 2016
Xcel Energy Inc. ^{7, 16}	XEL.N	Sell	N/A	US\$43.88	21 Jul 2016

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

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