US Electric Utilities & IPPs

What Did We Learn at the AGA Conference?

Equities

Americas

Electric Utilities

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AGA conference yields a few novel avenues for Utility growth

Execution was largely the focus across the Utility universe, with a focus on identifying the next round on spending opportunities. Three interesting themes emerged: 1) discussion of expanding gas E&P ratebasing opportunities within BKH and NWE utilities, with implications as we look to NEE's forthcoming proposal (prior to any run up in gas prices). Given FL's growing reliance on gas, we sense a broader regulatory support for the concept; 2) a focus on future environmental capex spending needs, with a focus on the Western US, where many plants remain both unscrubbed and also without SCRs to address NOx. We suspect Regional Haze issues could yet drive another wave (and further shutdowns) across a wide array of plants later in the decade including AEE, DTE, and XEL among others. We suspect these mandates would be contemplated with compliance in the ~2020 timeframe in large part, with upcoming IRPs in ~2015 to delineate timeline for next build cycle. 3) Third consistent theme was around continued strong production growth out of Marcellus/Utica, with development opportunities exceeding initial expectations- most positive for DTE. We mgmt. to upsize its Nexus project in the near term off the back of growing demand. Meanwhile, we note continued caution from others around the ability for incremental gas projects to address gas constraints seen this winter in NJ and NY.

Best stories of the conference? NU and DTE

While NU appeared not only to have growing confidence around its Northern pass transmission line NH, but also suggested it was open to looking at transmission to bring wind down from Maine as well as taking ownership in proposed gas pipeline. As for DTE, upsizing of its proposed Nexus pipeline given greater interest from both utilities and producers. Further, DTE remains constructive on the ability to fund further expansions of its gathering network and Millennium pipeline expansion. Lastly, its initial view on long-term electric utility capex suggests an accelerating trend on the back of more coal retirements and greater renewable mandates. We also reiterate our Buy on SRE, seeing the company as well under way on executing an organic MLP strategy, rather than acquisitive strategy previously contemplated.

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Links to our most recent notes:

AEE: Back to the Regulatory Drawing Board (May 9)

AVA: Ecova: Let's Make a Deal (May 8)

DTE: Cranking Up from a Cold Start (April 28)

ED: Steamy Winter in the City (May 9)

NU: In Pursuit of the Northern Passage (May 6)

PCG: Still Doing the Limbo (May 2)

PEG: Energy Half as Strong but Who Cares? (May 2)

SRE: Unleashing the Rex (May 7)

TE: Pushing for a Finish in New Mexico (Apr 30)

XEL: An Ambitious Agenda (May 5)

Figure 1: Schedule for UBS meetings at the AGA conference on Sunday, May 18th

SUNDAY, MAY 18		
Time	**Company**	**Management Participating**
pm 12:00 - 12:35	Avista (AVA)	Scott Morris, CEO Mark Thies, CFO Kevin Christie, Senior Director of Finance Jason Lang, IR
12:45 - 1:20	Consolidated Edison (ED)	Unconfirmed
12:45 - 1:20	Spectra Energy Corp (SE)/ Spectra Energy Partners (SEP)	Gregory Ebel, CEO or John Patrick Reddy, CFO
1:30 - 2:05	Xcel Energy (XEL)	Teresa Madden, CFO Paul Johnson, VP, IR
1:30 - 2:05	UGI Corporation (UGI)	John Walsh, CEO or Kirk Oliver, CFO
2:15 - 2:50	Integrys Energy Group (TEG)	Larry Borgard, President & COO Jim Schott, VP & CFO Steven Eschbach, VP - IR Donna Sheedy, Manager - IR Bill Guc, Treasurer - TBC
2:15 - 2:50	Questar Corporation (STR)	Ronald Jibson, CEO or Kevin Hadlock, CFO
3:00 - 3:35	National Fuel Gas Company (NFG)	Ronald Tanski, CEO or David Bauer, Principal Financial Officer
3:00 - 3:35	TECO Energy (TECO)	John Ramil, CEO Sandra Callahan, CFO
3:45 - 4:20	Northeast Utilities (NU)	Phil Lembo, Treasurer Jeff Kotkin, IR
3:45 - 4:20	Southwest Gas Corporation (SWX)	Jeffrey Shaw, CEO or Roy Centrella, CFO

Source: UBS/ AGA

Figure 2: Schedule for UBS meetings at the AGA conference on Monday, May 19th

MONDAY, MAY 19		
Time	**Company**	**Management Participating**
am 8:00 – 8:45	Black Hills Corporation (BKH)	David Emery, Chairman, President & CEO Anthony Cleberg, CFO Linden Evans, COO Garner Anderson, VP-Treasurer
9:00 - 9:35	DTE Energy (DTE)	Steve Kurmas, DTE Energy President and Chief Operating Officer (COO) Peter Oleksiak, Senior Vice President and Chief Financial Officer (CFO) Anastasia Minor, Executive Director, Investor Relations
9:45 - 10:20	Empire District Electric (EDE)	Brad Beecher, President and CEO Laurie Delano, VP-Finance and CFO Jan Watson, Secretary-Treasurer
10:30 - 11:05	Atmos Energy Corporation (ATO)	Kim Cocklin, CEO or Bret Eckert, CFO
10:30 - 11:05	CMS Energy (CMS)	Tom Webb, CFO
11:15-11:50	Ameren Corporation (AEE)	Matt Thayer
pm 1:00 - 1:35	PG&E Corporation (PCG)	Chris Johns, President of Pacific Gas and Electric Company Sara Cherry, VP of IR
1:45 - 2:20	Northwestern Corp (NWE)	Brian Bird, CFO Dan Rausch, Treasurer Travis Meyer, IR
2:30 - 3:05	Pepco Holdings (POM)	Joe Rigby, CEO Fred Boyle, CFO Dave Velazquez, EVP, Power Delivery Jeff Snyder, Assistant Treasurer Margaret Barry, Finance and Treasury Manager
3:15 - 3:50	Sempra Energy (SRE)	Dennis Arriola, President of SoCal Gas Richard Vaccari, VP, M&A
4:00 - 4:35	Public Service Enterprise (PEG)	Unconfirmed
4:45 – 5:20	NiSource, Inc. (NI)	Robert Skaggs, CEO or Stephen Smith, CFO

Source: UBS/ AGA

Other Sector Thoughts

Hedging Policies in focus: could utilities be poised to add to their positions?

Given the continued commentary from many management teams suggesting more limited upside in the near term to power, we suspect hedge levels are likely to improve appreciably in the quarter (2Q) as companies seek to continue to lock in the rally. We believe this could very well be the 'true' indicator of company's views on power, judging by their actions. We juxtapose PEG's latest more cautious comments on the viability of Eastern gas constraints with EXC's suggesting more limited fundamental upside to the markets on its 1Q call to suggest both PJM generators are bias to hedge up the rally. Meanwhile, we flag comments from Calpine among others as suggesting the prevalence of cheap gas could yet drive greater interest in getting involved in the sector, as well as driving PSEG's decision to invest in CCGT uprates. Overall, we flag a bullishness on spark spreads in PJM rather than absolute power prices. While the latest rally does give us some pause (with 2015 trading much closer to 2014 realized prices than we care to admit), we believe a rally could yet persist into later this year as liquidity flows into Summer 2015. We believe 2015 could very well be the top of the energy/power cycle (much as it was for capacity, with new gas entry and more limited coal retirements in 2016 onwards set to loosen the outlook).

How about transmission ROEs? It appears there is some comfort for a decision

We flag some utility comfort that the recent reappointment of LaFleur as Commissioner on FERC could yet drive nearer-term resolution to the pending 206 ROE case. While we are still cautious on a near term decision, we note many companies appear poised to go back in and file subsequent 205 cases (in MISO) to true-up their rate structures to at least reflect the 50bp RTO participation adder (Ameren has filed as such). We also suspect ITC and ATC will file for the 100 bp independence adder as well. This would appear to be a further test of FERC's commitment to transmission policy, although once adding back the adders, would likely have a very modest effect on any reduction in authorized ROE. Forthcoming changes in composition of FERC Commissioners could yet drive evolution of the rate paradigm.

Ameren Corp (Neutral, $40 PT)

Regrouping in Missouri

Could AEE be forced to dedicate more capital than it would prefer to Missouri for environmental purposes?

Management moved to dismiss concerns around ROEs in Missouri on two fronts: (1) the need for incremental environmental capital spending without timely recovery and (2) the continued frustration around regulatory lag in the state. The company has been successful in executing on its new regulated business model where it tactically shifts capital spending towards more profitable regions, notably both Missouri and FERC regulated transmission; however, investors remain concerned about the need to eventually elevate the level of spending in Missouri for environmental/reliability reasons at some point.

There is a playbook for MO environmental cost recovery.

Management characterizes itself as 'well positioned' on environmental in next handful of years due to its use of low sulfur coal and other mitigation factors. Plants such as Rush Island and Merrimack are candidates for additional environmental spending (whether it is scrubbers, conversions, or some alternative) but believe they have flexibility in their plan. Even in a 'worst case scenario' where material capital spending would be needed in Missouri, management pointed to its history with Sioux and the environmental rider which allowed Ameren Missouri to recover its capital without any lag. The environmental cost recovery mechanism on the books easies concerns on this front. Turning towards legislation, management reiterated that a key priority is securing more favorable treatment in the state that reduces lag and plans to utilize lessons learned during the most recent attempt in its next effort in the legislative process. We see the push for legislative reform in Missouri as primarily addressing spend likely to really only begin late in the decade, rather than necessarily near-term issues.

Sun unlikely to set on EIMA

Mgmt remains confident that it will continue to enjoy formula rates into the 2020s.

Ameren Illinois reported that it was successful in keeping its rate inflation below 2.5% through its first mid-2014 (as we discussed in our last Ameren note, rates actually are lower than they were in 2011 and among the lowest in the state). While further dated, there has been some lingering concern about the potential for Ameren to possibly lose its formula rates under the EIMA if the recent upward trend in power prices is sustained. The key nuance that shields Ameren is that the 2017 filing is more of an advisory report rather than a 'bright line' test so there is more leeway here – the 2.5% annual rate inflation is not a hard-and-fast rule. While Ameren is optimistic that it will not breach the inflation hurdle, it noted that the source of the rate inflation will be key and will be separated into delivery related as well as generation components. Due to the success of this mechanism, we would look for Ameren to move for implementation of the full ten-years (through ~2022). *Overall, we 're more comfortable in Ameren's ability to make use of the structure through its full ten-year span.*

Flexing the incumbent muscle

Ambitions to build transmission in neighboring states.

Without diving into details, Ameren expressed an interest in working on transmission projects outside of its Illinois/Missouri service territory but still within the regional footprint. Management believes that its resume in executing on transmission projects (which it hopes to build upon with Illinois Rivers) will give it a competitive edge. Neighbors Westar and Great Plains Energy have opted for

partners in some of their transmission projects but Ameren commented that it has not seen the need for partners thus far. Having said that, Ameren does have employees looking for transmission opportunities with potential partners and specifically noted that there could be work with Entergy in its MISO integration as well as in other reliability projects. Again, management did not announce any specific projects or areas of high interest but it is clear that it has ambitious to continue its transmission success.

'Sharpening the pencil' on costs of the final IL Rivers project.

Expect modest upward revision in transmission capex with next quarterly call

Focusing on Illinois Rivers, now that the final route has been approved we still look for the final approved cost estimate here but this is more a matter of refinement (i.e. 'sharpening the pencil') and not a question of refiling for the changes to the route.It appears that there is an opportunity to invest slightly more than the $1.3Bn (note that this estimate was originally a range and not a point estimate). Management was also quite to point out that legislation enabled in ~2011 around citing authority in Illinois for transmission, requiring a mandated timeline on decision making was the only way the project remained broadly on schedule.

Rounding out the conversation on transmission we note that Ameren has already indicated with the FERC that it would seek a 50bp RTO participation adder if there is any reduction in FERC regulated ROEs.

Avista Corporation (Neutral, $30 PT)

Ecova, Ecova, and More Ecova

A few incremental thoughts on Ecova.

The conversation at our AGA meeting was dominated (predictably) by Ecova following management's announcement that on the 1Q14 earnings call that it was "in the process of exploring the possibility of selling our interest in Ecova," its 80% owned IT/EE management business after having received multiple offers. We dove into details in our post-earnings note [link above] but learned a few new details (management still remains tight-lipped at this time). We still look for a decision on the decision to divest/not-divest the business by 3Q14; however, it remains somewhat indeterminate if that means *by* the 3Q14 earnings call (near EEI presumably) or during the quarter (perhaps as early as July?). Avista noted that it would be willing to accept stock in the transaction but only if the risk profile was right (i.e. it would appear unlikely that it would be willing to accept paper in a high-risk/beta company but all options are still on the table). Management left the door open to the possibility of selling only a portion of the business and reiterated its desire to see the business thrive in Spokane given that ~50% of Ecova's jobs are located in Avista's service territory. ~60% of Ecova's business comes from cross-selling and it could make for a strong strategic fit for many acquirers given its depth of Fortune 500 clients. Ecova also does not have a substantial international footprint, an area where Avista admits it does not have expertise given the nuances between foreign countries, yet another reason for its decision to potentially divest.

The primary catalyst for management disclosing that it was seriously pursuing a divestiture of Ecova is the pending AERC closing

The primary catalyst for management disclosing that it was seriously pursuing a divestiture of Ecova is the pending AERC closing (still expected by July 1), it appears unlikely that a sale could materialize ahead to offset financing needs – furthermore the AERC transaction is an equity deal. Given AERC's June 10 shareholder meeting, Avista had to disclose by May 9 (thirty days prior) the latest Ecova deals. Interesting, management commented that it would not have notified the market about its intentions this early in the absence of the AERC transaction.

No need for external Insight

Ecova's primary owner aside from Avista is Insight Venture Partners, a prominent private equity firm and Avista noted that it can choose to transact on its 80% ownership in the business without any minority partners opting to transact or approve the valuation.

Proceeds are highly contingent on the valuation basis.

We are growing increasingly positive on the potential upside proceeds from a deal and point towards the EV / EBITDA and revenue multiples approaches in our above referenced 1Q14 earnings note as indicative as possible upside over our 'base case'. One topic that still remains in the dark is use of proceeds which could range from funding utility operations, repurchasing stock, a special dividend, or paying-down debt (or a mix of those choices). Management once again pointed towards EV / EBITDA and revenue multiples as appropriate valuation metrics while noting that most of its comps do not have positive Net Income or even EBITDA. We currently assume all net proceeds will be utilized to buyback stock, a simplistic assumption given the dearth of information but note AVA's approximate authorized capital structures by jurisdiction below:

(1) Oregon/Idaho: 50% Equity/50% Debt

(2) Washington: 47% Equity/53% Debt

(3) Alaska (Pending AK Approval): 54% Equity/46% Debt

Figure 3: Net Proceeds Scenario Analysis

Scenario 1: Price/Earnings Approach			
Base Case	**Net Income**	**P/E**	**Value**
Gross Proceeds (A)	$13.59	18.4 x	$250
Investment Basis (Disclosed 12/31/13)			-$81.9
Gain			$168
Less: Tax at 15% (B)			$25
Net Proceeds (A) - (B)			**$225**

Scenario 2: Price/Sales Approach			
Bull Case	**Op. Rev**	**Price /Sales**	**Value**
Gross Proceeds (A)	$265	2.0 x	$531
Investment Basis (Disclosed 12/31/13)			-$81.9
Gain			$449
Less: Tax at 15% (B)			$67
Net Proceeds (A) - (B)			**$463**

Scenario 3: EV / EBITDA Approach			
Alt. Bull Case	**Op. Rev**	**Price /Sales**	**Value**
Gross Proceeds (A)	$43	9.9 x	$427
Investment Basis (Disclosed 12/31/13)			-$81.9
Gain			$346
Less: Tax at 15% (B)			$52
Net Proceeds (A) - (B)			**$376**

Source: Company Filings and UBS Estimates

Figure 4: Ecova Scenario 1: P/E Approach

Scenario 1: Price/Earnings Approach	
Base Case	
New Net Income (Ex-Ecova)	$125.39
Mn Share Reduction via Buyback at $31	7.3
New Sharecount (Mn)	60.7
New EPS	$2.07
New Multiple (Regulated Peer)	14.5 x
New Valuation	$29.97
Legacy Net Income (with Ecova)	$139
Old Sharecount (Mn)	67.9
Legacy EPS	$2.05
Legacy Blended Multiple	14.9x
Legacy Valuation	$30.45
EPS Accretion	$0.02
Multiple Dilution	-0.4 x
Higher/(Lower) Valuation	($0.48)

Source: Company Filings and UBS Estimates

Figure 5: Ecova Scenario 2: P/S Approach

Scenario 2: Price/Sales Approach	
Bull Case	
New Net Income (Ex-Ecova)	$125.39
Mn Share Reduction via Buyback at $31	14.9
New Sharecount (Mn)	53.0
New EPS	$2.37
New Multiple (Regulated Peer)	14.5 x
New Valuation	$34.32
Legacy Net Income (with Ecova)	$139
Old Sharecount (Mn)	67.9
Legacy EPS	$2.05
Legacy Blended Multiple	14.9x
Legacy Valuation	$30.45
EPS Accretion	$0.32
Multiple Dilution	-0.4 x
Higher/(Lower) Valuation	$3.87

Source: Company Filings and UBS Estimates

Figure 6: Ecova Scenario 3: EV/EBITDA Approach

Scenario 3: EV / EBITDA Approach	
Alt. Bull Case	
New Net Income (Ex-Ecova)	$125.39
Mn Share Reduction via Buyback at $31	12.1
New Sharecount (Mn)	55.8
New EPS	$2.25
New Multiple (Regulated Peer)	14.5 x
New Valuation	$32.58
Legacy Net Income (with Ecova)	$139
Old Sharecount (Mn)	67.9
Legacy EPS	$2.05
Legacy Blended Multiple	14.9x
Legacy Valuation	$30.45
EPS Accretion	$0.20
Multiple Dilution	-0.4 x
Higher/(Lower) Valuation	$2.13

Source: Company Filings and UBS Estimates

Figure 7: Ecova Comps (Energy Management/Small Communication & Large Payment, CRM, and Consulting Peers)

Company	Ticker	Industry	Latest Available	Market Cap ($Mn)	Analysts	'15 P/E	'16 P/E	'15 EV/EBITDA	'16 EV/EBITDA	'16 EV / Sales
Converse	CNSI	Communication Services	2015 EPS	537.6	2	26.8x	N/A	N/A	N/A	N/A
Tangoe	TNGO	Communication Services	2016 EPS	567.2	6	15.3x	11.3x	14.5x	N/A	N/A
Itron	ITRI	Energy Management	2016 EPS	1,506.5	13	16.3x	14.4x	8.4x	6.6x	0.7x
EnerNOC	ENOC	Energy Management	2016 EPS	710.7	8	27.4x	18.3x	4.9x	3.1x	0.5x
Ameresco	AMRC	Energy Management	2015 EPS	285.2	3	21.9x	N/A	N/A	N/A	N/A
World Energy Sol.	XWES	Energy Management	2015 EPS	52.1	-	20.0x	N/A	N/A	N/A	N/A
Mean				609.9	5	21.3x	14.7x	9.3x	4.8x	0.6x
Median				**552.4**	**5**	**21.0x**	**14.4x**	**8.4x**	**4.8x**	**0.6x**

Company	Ticker	Industry		Market Cap ($Mn)	Analysts	'15 P/E	'16 P/E	'15 EV/EBITDA	'16 EV/EBITDA	'16 EV / Sales
Concur	CNQR	Business Support (CRM)	2016 EPS	4,645.6	18	82.2x	59.8x	34.0x	26.0x	4.7x
SciQuest	SQI	Business Support (CRM)	2016 EPS	418.7	9	44.9x	38.8x	27.7x	N/A	N/A
Accretive Health	AH	Healthcare Software (CRM)	2016 EPS	729.5	2	17.5x	18.5x	N/A	N/A	N/A
Accenture	ACN	Management Consulting	2016 EPS	52,131.0	24	16.0x	14.9x	9.0x	8.5x	1.4x
ICF International	ICFI	Management Consulting	2015 EPS	738.6	6	14.3x	N/A	7.5x	N/A	N/A
Fleetcor	FLT	Payment Processing	2016 EPS	10,134.9	8	20.8x	18.7x	N/A	N/A	N/A
Wright Express	WXS	Payment Processing	2016 EPS	3,587.2	10	16.3x	14.1x	9.7x	N/A	N/A
GreenDot	GDOT	Payment Processing	2016 EPS	671.8	18	11.7x	11.3x	N/A	N/A	N/A
HigherOne	ONE	Payment Processing	2015 EPS	273.8	7	7.9x	N/A	N/A	N/A	N/A
ADP	ADP	Payroll Processing	2016 EPS	37,150.8	23	22.1x	19.7x	12.6x	11.3x	2.4x
Paychex	PAYX	Payroll Processing	2016 EPS	14,840.6	22	22.1x	20.6x	13.4x	13.1x	5.8x
Mean				11,392.9	13	25.1x	24.1x	16.3x	14.7x	3.6x
Median				3,587.2	10	17.5x	18.7x	12.6x	12.2x	3.6x

Overall							
Mean	7,587.2	11	23.7x	21.7x	14.2x	11.4x	2.6x
Median	**729.5**	**8**	**20.0x**	**18.4x**	**11.1x**	**9.9x**	**1.9x**

Source: Company Filings, FactSet and UBS Estimates (for CNQR and ACN)

What opportunities are available in Alaska?

Could AVA move to participate in further Alaskan M&A?

We look for further updates on the incremental opportunities in Alaska following the AERC deal closing (still on target for July 1st given the June 4th Commission six-month timeframe for approval). With respect to the deal, management says the two comments received on the acquisition have been largely positive but it remains conservative about talking about opportunities before securing the final commission approval. AERC is unlikely to file a rate case prior to the transaction closing and interestingly management noted that it has been approached by other regional utilities about potential M&A in the space/consolidating up the state. While it appears hesitant to do so immediately given the pending transaction this certainly does appear to be a further avenue for the company. The question remains whether it could or would seek to re-capitalize with a Holding company at the parent under the context of further expansions.

LNG and CNG opportunities are abound but have yet to materialize

Management discussed its willingness to continue pursuing small scale LNG and CNG ventures (via its SAILX subsidiary) but we again remain somewhat skeptical without more clarity here.

Rate case strategy: Is the playbook the same?

Management might not follow the same rate case strategy playbook.

We would look for management to pursue another multi-year deal in its Washington rate case given that the Commission has a preference for longer deals but there are two key factors that could influence Avista's decision making this time: (1) the increased uncertainty in interest rates/gas prices and (2) management

had more latitude to control costs in the last settlement given its human capital management ongoing at the time. Mgmt is still evaluating if it makes sense to file in Idaho at this time (overearned and held back revenue last year for customers).

Black Hills Corporation (BKH) (Unrated)

Drilling for a Mancos Exit

The company hopes to monetize this asset once the full value can be proved out and realized in a transaction

BKH continues to execute its plan to drill 12-15 wells in its Mancos acreage with the goal of proving out at least 2 TCF of shale reserves at 160 acre spacing over the baseline 74,100 acres held. This does not include an additional 20,000 net acres of Mancos Shale leasehold that was earned by drilling and completing two wells in the southern Piceance Basin in 2013. The company hopes to monetize this asset once the full value can be proved out and realized in a transaction, as it successfully executed on the previous Baaken sale. Management described its process as cautious and deliberate, with no urgency to rush as all leases are held by current production. After a sale, proceeds are most likely to be directed toward further finding and development costs as well as other possible investments across the company, including additional possible acquisitions (provided prices are reasonable) and/or new generating assets and renewable investments in Colorado. BKH is also interested in ratebasing its reserves, including the capital for finding and development, noting that its lower cost of capital could make its E&P business particularly competitive and attractive to regulators who are concerned about the potential for rising gas prices.

Coal Contract Step-up Coming This Summer

While most of the coal business is under long-term affiliate contracts earning a cost-plus utility return (A-rated bonds plus 400 bps), some off-site IPP contracts are subject to reopeners that will reset this year. Specifically, Pacificorp's Wyodak plant receives 1.4M tons of BKH's total 4.2M tons produced annually and has a fixed-price contract with escalators that reopens on July 1, 2014. The new price will be based on the recent 1-year average market price (now known and calculated) plus the avoided cost of shipping, which is intended to keep the contract competitive with market at 5-year intervals. The current price is only about $12/ton ($0.75/MMBTU) and is expected to reset several dollars higher due mostly to higher rail costs and continued PRB price inflation given the last price was established more than 5-years ago. BKH's own non-regulated Wygen IPP project also has a similar escalating fixed-price contract with re-openers set for 2018. The company has already been given a green light to ratebase the plant and intends to do so in about a year and a half from now, when depreciation will make the transaction rate neutral for customers while providing a $50M gain (equity) to BKH.

Muni Rollups Continue

While load growth is about 1%-2% annually, the utilities have limited transmission growth opportunities (some between Cheyenne Light and BHP) but continue to execute an ongoing muni rollup strategy throughout the Midwest. Munis are usually acquired essentially at depreciated cost but are ratebased at values closer to

original undepreciated book. While these are small dollar opportunities relative to other spending, the economics are very strong and Public Service Commissions frequently refer municipals to BKH as a good partner to handle compliance, etc.

CMS Energy Corporation (Unrated)

Upping the RPS and lowering the ROA

Currently CMS has ~$300Mn of incremental renewable spending in its 'opportunity' bucket above the standard ten-year capital spending plan and this amount would essentially double to $600Mn if the Renewable Portfolio Standard (RPS) is increased to 20% from 10% currently. Furthermore there could be some tweaking of the RPS aside from the headline number, possibly opening the door for CMS' pump storage upgrades to count as renewables. Management noted that potentially driving this $300/600Mn spending number even higher is that the 50% spending limit under the new renewable regime could go away, thus allowing CMS to capture even more incremental spending.

CMS state that the elimination of Retail Open Access (ROA) is within sight, potentially in 2015 could be yet another catalyst supporting CMS incremental spending as 780MW ROA limitation would provide overhead headroom for additional gas/electric work to be done without rate inflation.

Pivoting on propane; customer switching is big opportunity

CMS currently has ~250K consumers who utilize propane which is most costly, less safe, and showed reliability issues this winter. Out of the 250K, management noted that it was already economic for ~85K (1/3rd) to switch to natural gas without the need for new lines to be built. For these customers the payback period would be around two years; however, could be cut in half if legislation is passed that moves in the direction of socializing more of the costs here. Despite such a short two-year payback under the current construct, it appears that many customers are waiting for legislative change to make the economics even more advantageous.

Latest winter shortages and price spike likely to accelerate switching trend

'Blocking and tackling' remains the biggest opportunity

Out of management's additional capital spending contemplate outside of the base case plan the biggest component is $2Bn for reliability and CMS admits that there are lots of spending opportunities for the company to improve. Highlighting the need here was the anecdotal example of distribution poles that CMS' can visually tell need replacing as they are askew from normal (i.e. these are not 'fringe' spending projects but core needs). Again, a key here will be the degree to which overall O&M can be reduced to make headroom for this incremental spending without driving significant bill inflation. While Michigan does have above-average utility rates, it has below-average load thus its bills remain below the national average.

The nuclear option: unlikely to re-contract & w/o regulatory recourse

Management briefly touched upon Palisades and the outlook for nuclear in Michigan by noting that they still believe in nuclear generation but it will need to be economical. As such management believes Michigan will not step in to save the plant despite the forthcoming 111(d) carbon considerations, with the state having

State will not save ETR's Palisades plant

already achieved the bulk of the reductions contemplated under the 2005 standards. With nuclear generation becoming increasingly less economic in certain regions of the US, we believe this topic will continue to remain in focus.

Investment Grade options: bias towards improvement still

Consolidated FFO/Debt = ~18%
BBB Range = 17-19%

Now that CMS Energy's parent debt is investment grade for the first time in many years, the question becomes what is the opportunity to incrementally deploy the balance sheet. While management would like to further improve the balance sheet and pay-down debt, it is in no hurry to do so and logically prefer deploying capital into the utility with higher return profiles. From a consolidated FFO / Debt standpoint we understand that Moody's and S&P target 17-19% for BBB rating and currently CMS is at 18%.

Consolidated Edison (Neutral, $55 PT)

Harlem explosion clarity remains elusive for now

Statement of fact report from NTSB likely in June-September window.

The National Transportation Safety Board (NTSB) is leading the investigation into Con Ed's March 12 gas explosion that killed eight in Harlem and has Con Ed, the city of New York, and the NY PSC are all parties to the investigation. Importantly being a party on the case means that the entities are privy to the proceedings with the ability to fact-check, etc. with the caveat being that ability to opine publicly is limited. Consequently, we would not expect to hear any material updates from any of the parties ahead of the NTSB's investigation conclusion. The first real data point will come ~3-6 months from the event (June-September window) when the NTSB releases its statement of facts on the incident but will not include any conclusion. It appears that we will not receive real recommendations from the NTSB for another 8-12 months, which means that the overhang could linger for shares throughout at least the balance of the year. We note that the street where the accident occurred was tested once in 2013 and twice in 2014 (February 10 and 28) with no leaks found. Given the qualifications placed on the PSC and other parties to the investigation, it does not appear likely that the PSC will opine on the tragedy at this time and has not yet opened a docket to investigate.

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

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

Taking a deep look into CECoNY

Cost management is key.

Management's 2014 guidance was surprisingly strong given the overhang of the CECoNY rate freeze and it appears that cost management is key. Keeping costs in check has been the modus operandi for Con Ed for at least the past five years and a driver behind the TTM ~9% earned ROE for CECoNY (note this is based on the actual capital structure vs ~51% equity in the past few years). In 2013 the earned ROE for CECoNY was ~8.9%. We expect management to file O&R electric and gas ratecases this summer; however, the real river will be the next CECoNY rate case which would likely be filed in early 2015 for rates effective January 2016 (~eleven month process). As a reminder, the electric settlement was effective for two years while the gas/steam settlement was for 2014-2016. For further details of the Con Ed rate settlement please refer to our note on the topic from early January.

Could the CECoNY rate case be the first in the 'Utility 2.0' model?

Potential for new framework in New York to be established in 1Q timeframe

Much has been made of recent comments out of New York about a shift to a new paradigm in New York with a potential incentive-based structure like that seen in the UK with RIIO and it is clear that we will see some new ideas coming out of New York. The continued focus on mitigating bill inflation is prevalent in New York and we expect the focus to remain elevated through election season. The first two pieces of 'Utility 2.0' will come before the end of the year on clean tech and distributed generation while the more wide-reaching aspects relating to the rate construction is likely around March 2015. Given expectations of CECoNY filing in

February it is possible that the PSC could require the rate case to comply with the new construction; however, it appears unlikely that a 2015 filing would have a radical change akin to the RIIO model but the verdict is out there.

Higher Hudson Valley: Emergency actions to limit customer inflation

While somewhat difficult to quantify at this time, management provided a rough approximation that the newly created Lower Hudson Valley capacity zone is responsible for ~10% rate inflation. Given that the PSC wants to send strong price signals to possibly spur capacity to return to the market it would appear that this inflation is here to stay at the moment and alternative reforms will be needed to compensate.

Balancing rate inflation with price signals.

Limiting customer inflation has been a key focus for NY State

AC Transmission gone for now but not forgotten

Management confirmed that there has been minimal progress on the Con Ed's AC Transmission proposal or any other Indian Point contingency projects outside of the "no regrets" plans. In February the PSC instructed the three bidders to re-submit their proposals using existing right-of-ways (largely owned by ED) but overall it looks like progress has stalled here, again looking like no real projects will pick-up steam ahead of the November election.

Minimal progress on the Con Ed's AC Transmission propos

New York solar: Ready for the spotlight?

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

ED views NY solar as still largely uneconomic.

Appears unlikely to materially expand solar investments under current construct

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

DTE Energy (Neutral, $78 PT)

Bluestone and Millennium Expansions Are Filling in the Whitespace

Midstream updates continue to show further expansions.

DTE discussed their recent 1Q completion of the Cabot transportation interconnect with the Bluestone Lateral to the Tennessee Pipeline and the 2Q expansion of the Bluestone transportation agreement with Southwestern. With these producer-driven agreements, Bluestone is expected to expand from 0.6 bcf/d to 1.0 bcf/d by 2016, primarily through increased compression on the existing 36 inch pipe. Another 0.5 bcf/day is possible with additional agreements (discussions are ongoing with multiple parties) and expansion of the pipe to 42 inches. Management also expressed confidence that the gathering system could be expanded as well.

On the Millennium Pipeline, transport of 0.8 bcf/day down to Ramapo NY could be increased by another 0.2-0.5 bcf/day post-2017, driven by strong pricing and producers that continue to surprise to the upside by multiple measures including total production, lower costs, and production per well. These announced expansions support the company's previous midstream operating earnings projection for 2018 of $130M, with the "whitespace" placeholder now reduced to $20M from $25M previously. There's been no change (yet) to the 10%-15% earnings CAGR from 2012 to 2018E.

Nexus Picking Up a Fourth Utility Customer

Three large LDCs currently anchor the project and a verbal agreement with a fourth should be finalized in the near future (weeks).

Much of the remaining "whitespace" in 2018 earnings is expected to be filled with the proposed 0.8 bcf/day Nexus pipeline (which is likely to be upsized to 1.2 bcf/d with an expanded 42" pipe given strong customer demand vs. 36" contemplated), which promises to be one of the company's crowning midstream achievements given the recent explosive interest in the project. Nexus would connect Utica and SW Marcellus to Dawn hub (and Chicago via Vector) and it continues to attract strong interest from gas utilities as well as producers (expected to be sponsored roughly 50%/50%). Three large LDCs currently anchor the project and a verbal agreement with a fourth should be finalized in the near future (weeks). Among the major drivers for this project is the continued fall-off of western Canadian gas supply to Dawn (down 4-5 bcf/day over the past 5 years) as increased Canadian oil production takes priority and Canada proposes to convert another 1 bcf/day gas pipeline from Alberta to oil transport. Basis between Dawn and Utica has been $1 or more with prices exceeding $50 this past winter for an unprecedented several weeks. Management also noted that with Utica/Marcellus set to become the largest North American basin by the end of the decade (~over 20 bcf/day or a third of US consumption vs 16-17 bcf/d total demand across the Northeast), producers have been increasingly desperate to export out of the region. With REX now fully booked eastward and southern lines also at full subscription, the desire to transport into new markets northward is intense. On the demand side, the conversion of coal to gas in Michigan also drives the need for Nexus as well.

New Extended Utility Capex Projection Through 2025

At the utility, DTE released an extended capex projection of $1.3B-$2.0B annually from 2019-2025 (increase of hundreds of millions per year at the midpoint from the current five year plan through 2018) that is supported by 2.6 GW retiring from 2021-2025 due to age, EPA's New Source Review and carbon rules as well as 316b water cooling rules. Some plants need a cooling water retrofit for 316b and/or scrubbers, but may be too close to retirement to justify the investment. Nevertheless, management currently leans toward a retrofit for Belle River despite the $1B cost for FGD and SCR on the 1,200 MW plant (~$800/kW retrofit appears among the most marginal we've seen thus far of late). The asset is the company's newest in the portfolio. The final decision will depend on gas/coal relative pricing. Separately, management commented on the plan to hold rates flat through 2018 despite a robust capex program as $650M of surcharges fall off. While flat rates are important, they emphasized that average monthly bills were more important for economic competitiveness and that DTE still has some of the lowest bills in the country.

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

P&I Growth To Continue After REF Installations

At P&I, growth is expected to come from three areas: (1) organic growth onsite at facilities, (2) renewable conversions of coal-to-wood, and (3) the 8th and 9th REF unit installations as well as optimization and the possible movement of some units to larger plants. Management also sees the possibility of M&A, rolling up onsite power businesses, especially as low gas prices incentivizes more interest in onsite Cogen facilities.

Empire District (Neutral, $23 PT)

What does a strategic review mean?

Despite focus on Asbury and Riverton execution, investors have an eye to the future.

Management commented that it is undertaking a strategic review in July where it will discuss renewable spending (wind/solar), capital allocation, etc. likely a catalyst for shares. On the persistent topic of what growth opportunities does EDE have in the back-half of the decade, management stated that it was laser focused on completing the Asbury and Riverton projects then navigating the associated rate cases before focusing on longer-date opportunities. Management commented that given its free cash flow profile after the peak capex years, it sees 'no shortage' of capex spending that it could execute on. In general management portrayed a high degree of confidence here with the caveat being that it needs to keep customer bill inflation in check following the major capital spending. For example, the Asbury component of capex alone accounts for 3-5% rate inflation alone. Management intends to file a case in late Summer/early Fall (perhaps as early as 2Q14 earnings call) with the six-month true-up capturing the in-service in Spring 2015. There is a need to avoid filing too early and risking not catching it in the true-up (historically a ~six month true-up) or waiting too long and not capturing all of the recovery.

Not following a transmission strategy

EDE does not appear to have material transmission opportunities in the future.

In 'check the box' fashion management discussed the implications of FERC 1000 commenting that it does not anticipate activity impacting it (either from competition encroaching on its territory or from EDE opting to do substantial development in its footprint). Management did comment that it continues to pursue recovery from SPP (lumpy misc. revenues) for transfer payments when in its opinion it is not adequately sharing in the benefits from the recent transportation spending.

Taxes monopolizes recent conversations in Missouri

We expect EDE to utilize similar mechanisms as Ameren to reduce lag.

Empire District faces the same challenging Missouri regulatory construct as Ameren and peers, all of which whom face regulatory lag for property taxes. As we have written about previously, we would expect for management to pursue the fuel adjustment clause to reduce some lag on its transmission. Despite a narrowly crafted bill, the legislature did not take action to help EDE or GXP as the state remains very consumer friendly and the legislature was largely tied up in state income tax issues during the latest session.

No issues with environmental on the horizon

Many of EDE's units have dry ash landfills and management stated that it is a good position on coal ash as well as regional haze.

Integrys Energy Group (TEG) (Unrated)

A novel contract in Chicago: Integrys seeks fixed charge in retail rates

The latest player to seek changes in retail.

In perhaps a trend to be set elsewhere, TEG will implement both a fixed and variable charge in its new supply rates to serve the city of Chicago. This new structure is designed to improve the profitability of serving low usage customers, while also reducing the uncertainty of serving customers.

Management appears confident retail outlook has bottomed in 2014.

Following a consistent trend, we see management's commentary as reiterating our belief that retail margins have likely reached their lows of late following a meaningful increase in commodity volatility this past winter. We flag recent datapoints suggesting retail margins returning to the upper end of many expectations (or perhaps surpassing them), reflecting a mid-single $/MWh margin. TEG management suggested upside from recent deals would be reflected/rolled into future quarter/annual results.

Northwestern Corporation (NWE) (Unrated)

David Gates Appeal Could Go Through 2014

Eyes on the rehearing for DGGS

Mgmt files for rehearing with FERC on recovery around plant costs

On May 1, NWE filed an emergency request for partial rehearing with FERC to challenge the recently ordered refund of approximately $27M of revenue collected under the 2009 stipulation for the David Gates Generating Station (DGGS). Should a full FERC appeal be unsuccessful, management could appeal through the US Circuit Court of Appeals. The rehearing decision timeline and appeals process is open-ended, although based on precedent; a decision might not be available until the end of this year or into 2015. With the company already having reserved $27M since the 2012 initial ALJ decision, management stated that any refund and potential write-down would have minimal ongoing financial impact (besides a potential 1x charge) with any successful clawback providing upside to current 2014 EPS guidance of $2.60-$2.75. NWE has argued that DGGS was constructed from 2009-2010 primarily to provide FERC-mandated transmission system balancing and ancillary services under a 2009 stipulation that allocated 20% of the plant's ratebase to FERC jurisdiction for the benefit of wholesale customers. Management expressed puzzlement at the brevity of FERC's April 17th order that ruled against this 20% allocation methodology. NWE argues that it constitutes retroactive ratemaking in that the project was pre-approved by the stipulation with Montana Public Service Commission and FERC Staff. DGGS ratebase of $137.5M (12/31/13) excludes the FERC portion, which is treated as revenue credits to MPSC jurisdiction customers. DGGS also includes a 50 MW spare turbine and the company intends to make disposition determination for the spare depending on the outcome of the appeal.

Ratebased Gas Reserves Still Collect Seasonal Revenues

Requirements to ratebase assets are specific.

Balancing act around proving the NPV of acquisition

On the ratebasing of Bear Paw and future additional gas reserves, the company described at least three conditional screens that must be met, including a 20-year NPV test vs purchasing through the forward curve, a levelized cost comparison, and a requirement that levelized costs be lower than forward curve prices within approximately 5 years or so. The newest Bear Paw South acquisition of 63 BCF proven reserves has a levelized cost of $4.10/dth. The company intends to recover the investment through its gas tracker (similar to Battle Creek initially and Bear Paw North currently) until it can be moved into ratebase in the next rate case. So far, NWE has purchased reserves to meet 32% of production needs vs a 50% target, with up to another ~$100M of investment possible. Management reminded us that revenues collected for ratebased (and tracked) gas reserves are not evenly distributed throughout the year but are volumetric and fluctuate seasonally like other utility revenues.

Hydro Sale on Track for September Decision Barring an Earlier Settlement

NWE's regulatory calendar remains busy.

According to NWE, the $900M PPL hydro sale remains on track with briefs and a hearing due at the MPSC on July 8 unless there is a settlement. Reply briefs are then due in late July with a decision expected on September 16. Management described widespread public support for the "repatriating" of these plants back to Montana ownership. While the agreed transaction price is $900M, only $870M will be ratebased, with the 194-MW Kerr asset (out of 633 MW total) excluded. Kerr does not earn a return in year one and the Salish and Kootenai Tribes have an option to purchase Kerr from September 2015 through 2025. While the Montana Consumer Counsel has objected to the price paid, management emphasized that the terms are in-line with other recent hydro transactions and very advantageous when compared with historical pricing >$3000/kW. On approval, the plan is to close into permanent financing of up to $500M debt, $400M equity and $50M from free cash flow. There is also the option to use a $900M committed bridge facility if necessary. The company has requested a 10% ROE in-line with the rest of the utility and reiterated the expectation for 7%-10% total company return (including dividend) post-acquisition.

Northeast Utilities (Buy, $51 PT)

What about the Northern Pass project? Escapes latest legislative efforts in NH.

Latest winter continues to enhance NPT odds of success.

We are incrementally more constructive on the outlook for the Northern Pass project. We perceive that New England States Committee on Electricity (NESCOE) may be poised to move forward with at least 1.2 GW of new transmission capacity into the region as part of its ongoing RFP efforts to contract for low-carbon resources to alleviate its resource adequacy deficiencies. We flag the latest win in the state to defeat efforts in the NH senate to change the Site Evaluation Committee (SEC)'s criteria for the project as a critical hurdle. We continue to suspect a palatable deal for stakeholders could yet be achieved, with an alternate route by year end (at a modestly higher cost) could bring the project to realization despite its latest delay (DOE expects to issue a draft EIS by year end, vs previous mgmt. expectations for a draft by late Summer). The SEC process in NH is expected to take the bulk of 2015, suggesting there could yet be another legislative attempt to tweak project selection criteria next session as well.

Schedule set finally in NH over scrubber prudency; sets stage for divestment?

We continue to perceive an agreement to divest the generation as a potentially constructive bargaining position in order to enable NPT.

The state of NH has finally established a schedule over the prudency of NU's Merrimack scrubber, the first step in addressing whether or not to mandate the divestment of the asset. While the state would presumably ensure recovery of capital, mandatory divestment would limit the company's ability to earn a return on the asset. Given the market outlook of late around capacity and energy prices, we no longer suspect the plant would be an immediate retirement candidate. That said, it remains unclear if the plant would be maintained in the long-term should gas prices in the region moderate—as such, given the critical focus around resource adequacy in the region, the NH PSC many not opt to continue to hold the asset in rate base. We continue to perceive an agreement to divest the generation as a potentially constructive bargaining position in order to enable the Northern Pass transmission line.

How about more transmission projects? We see more on the come.

A change in tact could see NU working on further Maine transmission projects.

We suspect NU is poised to develop/propose further transmission projects beyond the company's seemingly sole focus on developing the NPT project of late. Specifically, we anticipate a joint venture with National Grid and others around projects designed to bring down wind capacity from Maine; this could very well be included within the regional transmission effort underway by NESCOE rather than traditional contracting efforts before in front of the ISO-NE seeing as more of a public policy rather than reliability-driven project. While a decisive opportunity in our view, this is an abrupt about-face for a company that had previously advocated against this project citing cost inflation on consumers. We suspect proposal of additional growth projects could help position the company beyond simply relying on Northern Pass to achieve the mid to high end of its growth targets.

And how about Boston too? We think there's a potentially critical need.

Witchcraft in Salem -

Proposed plant appears unlikely to get off ground.. driving more transmission investment.

While we perceive the company as less than forthcoming at times around incremental opportunities, we see a real reliability focus in the Boston load pocket as forming given the seeming inability for Footprint Power Developers to repower the Salem Harbor power site into a new CCGT. We increasingly suspect the project will be materially delayed if not scuttled altogether under its current structure (owing in large part to a deal denying a dual-fuel permit to the plant). As such, we suspect ISO-NE could be poised to intervene in the market to expedite transmission into the region to backstop the plant. The plant had previously cleared in last year's capacity auction for delivery in 2016 at the auction's ceiling prices (reflecting the region's overall short position).

Opportunities arising out of gas midstream could be quite appealing.

ISO-NE would retain day to day operation of the project.

We continue to sense a note of optimism around the potential for NU to partner with its peer electric LDCs in New England around a minority ownership in Spectra's proposed expansion of the Algonquin Pipeline (among other proposed projects) in order to offset the negative impact to their balance sheet. The proposed structure before the NESCOE regulatory board (effectively the joint regulatory agency overseeing New England energy efforts between the governors) would involve the electric utilities proving to be the financial counterparties for any gas pipeline contract. ISO-NE would retain day to day operation of the project.

Devils in the details? We see two key risks to contracting for the gas pipeline overall, seeing its unconventional approach as garnering unwanted FERC scrutiny (or forced to given likely complaints by generators/interveners over the equity of the structure). Additionally, the precise mechanism around who would receive the added gas capacity remains unclear as well, particularly as specific generators receive the benefits of this capacity. We look for more 'meat' around this draft proposal to help crystalize whether or not the structure is actually achievable.

PG&E Corp (Neutral, $46 PT)

GT&S Retroactivity Looks Likely

On April 17, the California Public Utility Commission (CPUC) established a procedural schedule in the Gas Transmission and Storage (GT&S) ratecase that extended to March 2015. With The Utility Reform Network (TURN) and the Office of Ratepayer Advocates (ORA) now agreeing to retroactively apply rates out of the case to Jan 1, 2015, we see that outcome as likely (pending CPUC approval). As much of the gas system work proposed in the case is safety related and could not be delayed, this is a positive outcome for an especially large $1.2B revenue requirement request (a $555M increase in 2015 alone). <u>Historically speaking, we also note that the case is likely to take longer than March 2015 to get a resolution</u>.

Could a GTS ratecase outcome land before San Bruno PD?

GRC and San Bruno Probably not Connected

<u>With Commissioner Florio in charge of the GRC and Chairman Peevey in charge of the San Bruno investigation, it's unlikely the two significantly delayed outcomes are being held up for each other</u>. The company expects an PD for the GRC in a matter of "weeks", perhaps early June. The San Bruno investigation is probably being delayed by a desire to ensure meticulous legal documentation that will stand the test of challenges surely to come (from both sides). The company does not believe that either CPUC proceeding is affected in any way by the federal criminal case. PCG intends to release 8Ks shortly after each PD and final decision to outline the expected financial impacts. Under "normal" circumstances, we would expect the company to provide 2014 EPS guidance once final orders are in hand for both issues, with 2015 guidance released in the 3Q. In the past, multi-year guidance has been issued in 1Q as well (although there have not been 'normal' timelines in recent years).

GRC and San Bruno do not appear to be handcuffed.

Interest Shifting Toward Greenhouse Gasses and Away from RPS

While there has been limited push of late interest in expanding the state's Renewable Portfolio Standard (RPS) to 40-50% from today's 33% goal (2020), focus of late from the CPUC and Governor's office has emphasized GHG reductions. PG&E remains on track

Battery storage – intends to participate

While the RFP process will be released in December, management appears adamant it will participate in the storage buildout to the best of its abilities to capture incremental capital spend.

What about Oakley plant? Still pushing for it.

Despite push back on the failure to demonstrate the need for the plant, management remains adamant in pushing forward with the plant proposal again. This remains a challenging road ahead for the new CCGT expansion seeing the substantial over-supply in the state.

No guidance without clarity on both SB and GRC

Management does not intend to provide guidance until both San Bruno and the rate case are resolved. Additionally, we believe the company's dividend policy is due for an update subsequent to resolution as well. While management has historically committed to a 50-70% payout ratio, the latest comments would suggest a payout consistent with utility peers at 60%+ is the expectation.

Public Service Enterprise Group (Neutral, $41 PT)

Confidence on sustainability of gas basis advantage unclear

Altogether, we perceive bearish tone on pricing off current levels

We perceive PSE&G as relatively less constructive on the sustainability of the current uplift exhibited in forward power and gas in New Jersey following this winter's polar vortex. Altogether, we perceive bearish tone on pricing off current levels. While not necessarily citing any new developments per se (aside for further TETCO transport expansion into NJ), management downplayed the effect of the two contemplated new gas fired generation stations (LS Power's West Deptford plant and Hess' Newark Energy Center) on the overall uplift in the regional supply/demand. Management continued to harp on the lack of any meaningful fundamental growth in gas demand outside of gas generation.

In conjunction with our latest meeting with DTE yesterday, it appears clear that there could yet be further producer funded projects designed to push gas into the New York and NJ markets out of Leidy Hub. Management was particularly bearish on TETCO M3 prices, remaining/dropping to a negative basis for the majority and declining off its recent highs. In New York, we look for in-service of the Constitution pipeline (600 mcf/d) as well as Millennium Pipeline expansion (0.2-0.5 bcf/d incremental compression capacity) to ease upstate basis, which will be offset by the likely conversion of the Danskammer unit to gas from coal, a new CCGT potentially contracted with NY state, as well as the broader long-term implications of a shutdown of Indian Point (substantial uptick in regional gas demand). We reiterate our belief that adequate natural gas in this region to enable its retirement remains a growing concern of ours.

Improving Gas Prices at its Bethlehem CCGT plant

Boosting Bethlehem basis

Management elaborated on its recent improvements in gas pricing at its Bethlehem CCGT in upstate New York (near Albany), which was previously procuring off the Iroquois pipeline. Rather, management has been able to build a small lateral to an adjacent low-pressure Dominion pipeline off which it is able to source lower-pressure gas. The new interconnection has improved the plants basis by $0.50-0.60/MMBtu, seeing the plant was formerly competing for supply availability with the New England market. We suspect the plant will benefit from meaningfully improved sparks and dispatch prospectively.

So what about Firm Fuel? It's really all about Dual Fuel.

Management appears biased to believe that any discussion around fuel adequacy concerns by PJM (among other RTOs) are likely to focus firmly on the opportunity to employ dual fuel capabilities at units. While they have yet to see any activity to implement greater dual fuel capabilities in NJ citing environmental permitting constraints, and looser supply/demand balance, it would not be surprised to see such an outcome in New England.

How about the gas trends thus far this quarter?

Management emphasized that gas basis remained favorable through April, suggesting a 2Q benefit for PSE&G could yet be in the cards again (as well as the remaining Eastern generators).

Sempra Energy (Buy, $106 PT)

MLP Strategy continues to take shape

Refining the MLP options.

We emphasize an MLP strategy remains a clear goal for management, emphasizing that an organic strategy could very well take shape late this summer with greater clarity around new contracts for its REX pipeline (contracts for the 1.2 bcf/d backhaul as well as 600 mcf/d Seneca lateral), as well as clarity late this summer around bids for five projects out for RFP with CFE, with some of each of these products contemplated to have a US portion (which would be eligible for the MLP structure). Given the timeline for these projects to begin to enter service in 2016, it remains unclear whether management would be able to kick-start an MLP structure prior to the in-service of any of these pipes, although we suspect the ~20-25 year contract life of these long-haul pipes with CFE could certainly serve to backstop a high quality MLP (particularly with the Cameron LNG unit backstopping the structure once it reaches in-service in 2018-19). Net-net, we remain biased to think any MLP structure would start at an exceptionally modest size (<$50 Mn/yr in EBITDA), swiftly growing to $100-200 Mn/yr in order to trigger the 50/50 splits.

REX could only constitute 40% of any MLP structure

1940 Act could take a bite out of REX's ability to launch an MLP.

While REX appears among the most 'eligible' assets in Sempra's portfolio for its nascent MLP efforts, we emphasize its non-controlling 25% interest in the asset would limit the company's ability to leverage into the 'base' asset off which to launch an MLP. Rather, according to limitations under the 1940 Securities Act, any ownership of REX would be limited to 40% of the MLP. As such, we see this limitation as preventing an MLP structure from being formed prior to the in-service of the initial round of CFE (IEnova) developed gas midstream assets in 2016 (potentially disappointing to some investors, but a value enhancing proposition still in our view). Lastly, with the use of added cash flows from the latest backhaul contract unclear in terms of debt paydown strategy, it is unclear today how further EBITDA generated would be distributed back to shareholders. Additionally, with continued contracting risk in ~2019 around the expiration of its base $1.08/MMBtu base contract (off which the project was originally developed), it remains unclear what the 'long-term' cash flow profile of the asset will be (mgmt. could opt to employ a preferred structure, consistent with the strategy employed by Dominion to improve the quality of its Cove Point asset in its initial MLP).

Where is there upside in the SoCal Gas Story?

PSEP acceleration could meet regulators desires.

We continue to see the long-term growth opportunities for SoCal Gas as firmly tied to expanding gas needs along coastal sites to serve any new contracted generation assets procured through ongoing RFOs for new gas-fired capacity to backstop SONGS. <u>With new generation likely in the 2018-2020 period, we suspect incremental capex will only begin to impact the outlook toward the tail end of the current capex forecast through 2018.</u>

Where's the risk to the story? Next SoCal case will involve a bigger ask. Given the demands put on gas utilities in California from PHMSA and the CPUC, we suspect the subsequent rate case to be filed later this year for effect on January 1st, 2016 could very well involve a more significant rate increase than prior cases. We see this as the primary risk to the story, although flag PG&E's ability to implement a interim rate deal with interveners as a constructive datapoint given the clear risk around a protracted schedule.

In the nearer term, we look for an acceleration of PSEP spending. Hand in hand with the greater demand of regulators, we suspect added spend to meet these more stringent regulations could yet materialize, albeit at more modest sums.

TECO Energy (Neutral, $17 PT)

TECO moves a step closer to closing on NMGC deal: Constructive

Proposed settlement could result in NMGC deal closing in 3Q14 (mid-August)

Last Wednesday TECO announced that it has reached a settlement in its pending New Mexico Gas Company (NMGC) deal. Specifically TECO has made an agreement with the New Mexico Industrial Energy Consumers (consumer advocate) and the NM Attorney General which is not opposed by the NM Public Regulation Commission (PRC). The remaining hurdle for closing the deal is final PRC approval and management expects a decision in the next three months and is maintaining its expectation of closing in 3Q14 (likely by mid-August should ALJ move in a timely manner). The first step in the process is that the AG Staff has to file testimony (May 27) and TECO has to file briefs by June 6th to clarify points.

Figure 8: New Mexico Gas Company Earnings Estimates

New Mexico Gas Co. Earnings Contribution	2013E	2014E	2015E	2016E	2017E
Rate Base					
Beginning		$520	$548	$575	$603
Capex		$63	$63	$63	$63
Depreciation		$35	$35	$35	$35
End	**$520**	**$548**	**$575**	**$603**	**$630**
Rate base growth		*5.3%*	*5.0%*	*4.8%*	*4.6%*
Equity Layer	*52.0%*	*52.0%*	*52.0%*	*52.0%*	*52.0%*
Authorized ROE	*10.0%*	*10.0%*	*10.0%*	*10.0%*	*10.0%*
Earned ROE	*9.5%*	*9.5%*	*9.5%*	*9.5%*	*9.5%*
Earnings contribution (Pre-Interest)	**$26**	**$27**	**$28**	**$30**	**$31**
Synergies (Placeholder)		*$0.0*	*$2.71*	*$5.4*	*$5.4*
Rate Credits		*$0.0*	*($2.0)*	*($4.0)*	*($4.0)*
Parent Debt	200	200	200	200	200
Tax interest	4.5%	4.5%	4.5%	4.5%	4.5%
Tax	35%	35%	35%	35%	35%
After tax interest expense	5.85	5.85	5.85	5.85	5.85
Earnings Contribution (Post)	**$20**	**$21**	**$23**	**$25**	**$27**

$2Mn Additional Rate Credit in Settlement Agreement

Source: Company Filings and UBS Estimates

Decision to not raise rates before 2018 implies a late 2016 rate case filing.

Mgmt reiterated accretive statements despite stayout

Will elaborate on growth and synergy targets with deal close

We believe that the strategic rationale and value of the transaction lie not so much in synergies, but in load growth through propane conversions and a regional economic recovery

It appears that the only additional concession made to secure the settlement versus what was communicated on the 1Q14 earnings call is the decision to defer a rate increase until 2018 with other compromises unchanged. This latest concession will drive an additional ~$2Mn of rate credits in 2017 ($4Mn per year following $2Mn in the first year) and we continue to believe that the ~$10Mn (up from $8Mn previous UBSe) will largely offset the run-rate synergy benefits ($5M-$6M UBSe based on 6% savings on non-fuel O&M). Previously management stated that it expects the acquisition to be accretive after a twelve-month ramp and reaffirmed this comment at the AGA Conference. Management has not quantified the cost savings at NMGC, especially in the personnel area while it is pursuing regulatory approval but we would expect an update post deal closing when 2014 guidance is updated to include the effects of the transaction. We understand that TECO has offered to not reduce headcount at NMGC by more than 99 employees (out of ~600) in the first three years of ownership but there are ~38 potential job cuts at People's Gas as synergies flow back to Florida. Currently we do not include the People's Gas synergies in our accretion numbers above but they could be in the rough ballpark of ~$2Mn, helping to offset some of the bill credits discussed. Outside of synergy related benefits, management stressed the potential opportunities to increase spending at NMGC above the previous owner's level (essentially in-line with depreciation currently) – this was the strategy employed at People's Gas initially. While it may be unrealistic to expect NMGC to spend at 2x depreciation like People's Gas, there are opportunities in New Mexico for data

centers, propane conversions, etc. that can be a catalyst for spending. We believe that the strategic rationale and value of the transaction lie not so much in synergies, but in load growth through propane conversions and a regional economic recovery. Synergies should help the company keep ROEs up through the stayout and we expect little more than that. NMGC currently earns ~9% ROE vs 10% authorized. As a reminder, NMGC is worth ~7% of our consolidated TECO valuation ($17 price target, based on a '15E SOTP).

On the topic of further M&A, management stated that they had looked at Minnesota Gas too but rejected a potential deal because of legacy environmental liabilities. TECO continues to follow a "southern strategy" where management looks almost exclusively for growth in the southern states while staying away from Northern acquisition opportunities.

Figure 9: New Mexico Gas Company Earnings Dilution

New Mexico Gas Co. (Dilution)/Accretion Calculation	2013E	2014E	2015E	2016E
Pre-Acquisition (TECO Legacy)				
Net Income	$204	$215	$238	$253
Shares	216	215	215	215
EPS	**$0.95**	**$1.00**	**$1.10**	**$1.18**
Post-Acquisition (TECO + NMGC)				
Legacy Net Income	$204	$215	$238	$253
Contribution from NMGC (25% in '14)	$0	$5	$23	$25
Net Income Combined	$204	$220	$261	$279
Legacy Shares Outstanding	216	215	215	215
Shares Issued (At $17.75)	0	23	23	23
Weighted Average Shares Outstanding	216	221	238	238
EPS combined	**$0.95**	**$0.99**	**$1.10**	**$1.17**
NMGC Deal looks to be largely EPS neutral				
Change in EPS	**$0.00**	**($0.00)**	**($0.01)**	**($0.00)**

Source: Company Filings and UBS Estimates

Latest thoughts on Coal

Management wants to send a strong signal that earnings here are not core.

Our conversation at AGA naturally touched upon the Coal segment once again and management reaffirmed that the segment is not core and it wants to send a clear signal to the market about its intentions to exit (i.e. do not expect a partial transaction or TECO to retain some interest). Interested parties are not moving fast and there does not appear to be much of an urgency to close a deal but TECO stated that it could close a potential deal in as little as thirty days given that the same regulatory hurdles are not needed for this business. Management continues to emphasize that it wants to receive full value for Coal hence it remains unwilling to classify it as 'Available-for-Sale' (more likely than not will transact on the business in the next twelve months – a somewhat high standard and statement of intent).

Xcel Energy (Neutral, $32 PT)

Monticello: First fireworks around Fourth of July

Monticello update coming in next ~40 days.

The proceedings have narrowed in on prudency alone and the mechanism is not at question, essentially this is a "standard prudency review". The review is progressing and the parties will finalize their position around July. The next step is for an ALJ proposed decision in late December and whatever the Commission ultimately decides upon will be incorporated into the pending rate case, assuming there is something short of full recovery. Thus far management commented that the scope of the proceedings have held no real surprises despite being a "pretty comprehensive filing".

Which capex lever to pull first?

Solar, transmission, environmental spending - which button will management press first?

The pending solar RFP in Minnesota could see Xcel bid on either the regulated or unregulated side but it appears unlikely that management would take a strategy like Georgia Power (and bid from bid sides of the house). The problem with bidding from inside the utility is the ITC issue and normalization so management would likely prefer bidding at an unregulated intermediate entity. At the end of the day the potential uplift from the RFP is incremental but remains somewhat limited given that the 100MW at ~$2,000-3,000/Kw would have a relatively limited impact on earnings.

On a more longer-dated front, there is a possibility that additional environmental spending will be needed for Sherco 1 & 2 (~1,200MW Sherburne County Generating Station) as well as 1,000MW of additional Texas generation. Depending on how CSAPR part two plays out, there could be ~$800Mn of capex (~$200Mn for an SCR at each unit). On the related topic of equity needs, management stated that an update would be provided later this year and could shift around based upon a variety of factors, notably whether bonus depreciation gets extended or not. In context of the 4-6% growth forecast, management commented that if it earns around a ~10% consolidated ROE it would likely see growth around 4% with high ROE pushing the needle closer towards the 6% level. The combination of environmental spending, TransCo growth, and solar serving to primarily maintain the growth profile but not necessarily drive it higher within the range.

Latest in the long line of TransCos

Xcel looks to be the latest utility to move to establish a transmission holding company to capitalize on FERC formula rates and clearly separate the business to provide better transparency to investors. Management noted that while it has the option to transfer existing transmission assets into the TransCo via a novation process, it plans to start small and only put new assets into the structure at this time, thereby avoiding potential issues with local state regulators who may not look favorably upon losing jurisdiction over assets. We would ultimately expect Xcel to follow the lead of ITC and likely AEP by utilizing back-leverage at the parent to further enhance returns greater than the already high leverage at the operating company level. We still look for the TransCo to be up-and-running by later this summer when approval is received for the formula ratemaking and other administrative requirements are met. While management sees the clear benefits of TransCos, it stated that it has no desire to be on the cutting edge with either a REIT (given the absence of clarity in the relevant Private Letter Ruling) or a YieldCo (lack of appropriate assets).

Management has no plans to transfer assets out of state jurisdiction and into the TransCo – at least for now.

The question is how and when will mgmt. opt to use the Transco to develop – specifically the NM buildout recently approved in SPP

What partnership opportunities exist as well ?

Echoing that load growth is an art

We took a deep-dive into 1Q14 load growth data in our recent note on the topic and Xcel management reminded investors that it is waiting for more quarters of data before drawing any conclusions about the positive data seen in the first quarter.

Coloring Colorado its own shade

Management expects to file a rate case next month and just like we mentioned with Avista above, it appears that Xcel would prefer a longer-term rate agreement but a more 'hybrid' structure could be possible with various rider mechanisms. Boulder municipilization continues with two unanimous votes recently to create the legal structure necessary but this still looks like a work in process over the next few years.

Statement of Risk

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

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Sell	FSR is > 6% below the MRA.	11%	23%
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Sell	Stock price expected to fall within three months from the time the rating was assigned because of a specific catalyst or event.	less than 1%	less than 1%

Source: UBS. Rating allocations are as of 31 March 2014.
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Ameren Corp.[6a, 16]	AEE.N	Neutral	N/A	US$38.54	19 May 2014
Avista Corp[1, 3, 4, 5, 6a, 6b, 6c, 7, 16]	AVA.N	Neutral	N/A	US$31.88	19 May 2014
Black Hills Corp.[6b, 7, 16]	BKH.N	Not Rated	N/A	US$56.04	19 May 2014
CMS Energy[4, 5, 6a, 16]	CMS.N	Not Rated	N/A	US$28.88	19 May 2014
Consolidated Edison[4, 6a, 16]	ED.N	Neutral	N/A	US$54.30	19 May 2014
DTE Energy Co.[2, 4, 5, 6a, 16]	DTE.N	Neutral	N/A	US$74.70	19 May 2014
Empire District Electric Company[16]	EDE.N	Neutral	N/A	US$23.66	19 May 2014
Exelon Corp.[2, 4, 5, 6a, 6b, 6c, 7, 16, 22]	EXC.N	Neutral	N/A	US$33.97	19 May 2014
Integrys Energy Group[16]	TEG.N	Not Rated	N/A	US$57.26	19 May 2014
Northeast Utilities[4, 6a, 13, 16]	NU.N	Buy	N/A	US$45.26	19 May 2014
PG&E Corporation[6a, 16]	PCG.N	Neutral	N/A	US$43.52	19 May 2014
Public Service Enterprise Group[6b, 6c, 7, 16]	PEG.N	Neutral	N/A	US$37.17	19 May 2014
Sempra Energy[2, 4, 5, 6a, 6c, 7, 16]	SRE.N	Buy	N/A	US$97.08	19 May 2014
TECO Energy Inc.[16]	TE.N	Neutral	N/A	US$17.11	19 May 2014
Xcel Energy Inc.[4, 6a, 16]	XEL.N	Neutral	N/A	US$30.06	19 May 2014

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