US Utilities & IPP's
Getting Nuclear on Nuclear Costs [Transcript]

Industry aims to reduce costs back to 2002 levels by end of decade
We hosted our latest conference call with the NEI to discuss the latest industry wide plan to bring down costs back to the 2002 level of $28/MWh by 2020, leveraging reductions on capex, O&M, and nuclear fuel. Aggressive goals which many investors view with justifiable scepticism appear more plausible in a scenario where both capex and fuel costs continue to undergo a structural shift over the next few years. Capex peak of almost ~$11B in 2012 could be a cycle high for the medium term as many plants were transitioning from 40 to 60 year operating timeframes and upgrading expensive components like steam generators and reactor vessel heads. Further, Uranium price declines may still have a significant role to play in cost deflation as 5 year hedges roll off in a depressed commodity environment. On the other hand, O&M remains an area for significant improvement and relatively flat O&M costs aren’t helping the cost story when ~58% of total costs were operating-related last year.

Nuclear costs would help the generators offset headwinds: who benefits?
We emphasize declining nuclear cost cuts remain a key upside driver for the likes of EXC, PSEG, ETR, NRG, TLN among other generators. We think the targeted $7/MWh all-in cash reduction would meaningfully improve FCF for each of these companies. We believe this would appear to be among the single most bullish factors for these nuclear fleets, albeit with much of this accruing as a reduction in capex – and hence below the EBITDA line. See the tables below. We also emphasize the declining cost trends would benefit regulated portfolios as well including D, DUK, ETR, NEE, SO, SCG, etc.

It’s not just about IPPs: Keeping regulated units open too
With the nuclear industry facing ~$45/MWh costs for single unit sites in 2015, we emphasize even single unit sites under long-term PPAs or operated by regulated utilities are at risk for premature retirement. The NEI compares the latest slew of retirements to the last wave in the mid-1990s largely executed under regulated utilities. We see the latest focus shifting towards MI where ETR’s remaining single-unit plant, Palisades continues to run with an above-market contract (in the 40’s/MWh) with CMS. We emphasize shutting down this unit early could not only save money for ETR in operating the plant and accelerating its strategic positioning away from nuclear but also reduce delivered costs to CMS consumers avoiding the cost of such a high-priced PPA. While merchant IPPs have been on the front end of the latest retirement wave, we see a trend towards regulated entities should the industry prove unable to rein in costs. We emphasize with power prices across much of the country now trending below $30/MWh – and capacity contributing an additional $5-10/MWh, the implicit value of carbon remains the key ‘discrepancy’ in justifying the economics of these plants/

Looking for additional help too – nuclear units avoid filing against PPAs
For a look on next moves for the industry, we emphasize investors should appreciate that the nuclear IPPs recently got together- and purposefully did not advocate for the imposition of a Minimum Offer Price Rule (MOPR) on Ohio plants benefitting from above-market PPAs in the latest industry complaint. Implicit from this decision is a strategic view to avoid criticizing above-market industry payments as the nuclear industry itself may eventually benefit from such compensation as well, at least under the context of how plants would be able to bid. As a reminder the latest Ohio PPAs also included a nuclear plant too – Davis Besse as part of the contracted portfolio.
Can Nukes Cut Costs by 25% by Late this Decade

We hosted a call with the Nuclear Energy Institute (NEI) where they discussed the outlook for the nuclear industry, readily admitting that there are industry challenges but painting an optimistic picture of the future. While the industry suffers from the effects of cheap natural gas and other external considerations, NEI is refocusing internally to make its plants more efficient. The most significant discussion revolved around a desire to reduce total operational costs by $12/MWh off a $39.69/MWh 2012 base. This represents a 30% decline from the peak year and ~25% from 2014, targets that NEI readily admits are aggressive. The reductions are expected to be achieved with savings across the three main areas:

- **O&M -$3.50/MWh:** Improved efficiency at plant operations. O&M has increased ~1% over the years and has trended downward already since 2011. Increases are due largely to (1) operating the plant; (2) support services; and (3) work management. Ongoing efficiency programs proposed by NEI could drive further cost reduction but progress thus far has been modest.

- **Capex -$6.50/MWh:** Reduced capital requirements with $3.50/MWh of the savings already achieved as the industry moves back Fukushima spending. Capex cycle peaked in 2011 and could show further improvement as major capital programs slow down.

- **Fuel -$2/MWh:** Declining uranium prices could translate into deflationary environment as 2011 hedges roll off on 5 year contracts. Improved supply chain should also contribute to this deflation.

This objective of bringing costs down to ~$27/MWh appears quite ambitious with most unregulated operators having likely reviewed their respective cost structures in recent years while regulated generators have less of an incentive to control costs. For example Exelon announced a cost management plan with $175Mn target savings at its ExGen merchant subsidiary plus $50Mn of nuclear fuel savings. Even if the industry can achieve costs in the ~$27/MWh range, this will still leave individual units pressured in unfavorable market. For example ERCOT-Houston 2017 ATC pricing is ~$27/MWh and generators do not have the benefit of the capacity market to supplement revenues. At these prices even the lowest cost first quartile generators ($29/MWh) are seemingly losing money on an open basis.

![Figure 1: Historical and Target All-In Nuclear Costs ($/MWh)](source: Nuclear Energy Institute)
NEI is confident that US generators who request an additional license renewal to six years will be successful if they elect to pursue renewal but the situation is different in France. The French Court of Audit issued a report last week stating that it estimated ~€75Bn of capital costs (plus ~€25Bn O&M) were necessary to extend the life of EDF’s nuclear assets versus the company’s initial ~€55Bn.

**Who Benefits? ~$7/MWh could have major benefits to industry**

Execution against these targets would yield substantial savings off 2017 EPS and EBITDA (for IPPs). We show below the leverage off the key merchant portfolios below, emphasizing **EXC and ETR as the most sensitive** (albeit this still includes yet to retire plants). We see FE and TLN as also similarly leveraged to this reduction. NEE and D only include their single remaining merchant plant exposures.

**Figure 2: EPS/EBITDA Impact on Unregulated Nuke Fleet**

<table>
<thead>
<tr>
<th>Company</th>
<th>Avg Fleet MWh</th>
<th>Cost Improvement $7.00</th>
<th>Benefit ($M)</th>
<th>Net of 35% Tax</th>
<th>Share EPS Impact $0.78</th>
<th>EPS/EBITDA A $2.61</th>
<th>% of 2017 EPS/EBITDA</th>
</tr>
</thead>
<tbody>
<tr>
<td>EXC</td>
<td>157,793</td>
<td>$1,105</td>
<td>$718</td>
<td>922</td>
<td>$0.78</td>
<td>$2.61</td>
<td>30%</td>
</tr>
<tr>
<td>TLN</td>
<td>9,813</td>
<td>$69</td>
<td>$69</td>
<td>$63</td>
<td>$0.26</td>
<td>$2.94</td>
<td>12%</td>
</tr>
<tr>
<td>D (Millstone)</td>
<td>6,758</td>
<td>$47</td>
<td>$31</td>
<td>597</td>
<td>$0.05</td>
<td>$3.90</td>
<td>1%</td>
</tr>
<tr>
<td>NEE (Seabrook)</td>
<td>9,484</td>
<td>$66</td>
<td>$43</td>
<td>461</td>
<td>$0.09</td>
<td>$6.50</td>
<td>1%</td>
</tr>
<tr>
<td>NRG</td>
<td>9,087</td>
<td>$64</td>
<td>$63.61</td>
<td>2,909</td>
<td>$2.90</td>
<td>1%</td>
<td></td>
</tr>
<tr>
<td>PEG</td>
<td>29,107</td>
<td>$204</td>
<td>$132</td>
<td>506</td>
<td>$0.26</td>
<td>$2.94</td>
<td>9%</td>
</tr>
<tr>
<td>ETR</td>
<td>36,398</td>
<td>$255</td>
<td>$166</td>
<td>179</td>
<td>$0.93</td>
<td>$4.96</td>
<td>19%</td>
</tr>
<tr>
<td>FE</td>
<td>31,042</td>
<td>$217</td>
<td>$141</td>
<td>425</td>
<td>$0.33</td>
<td>$2.83</td>
<td>12%</td>
</tr>
</tbody>
</table>

Source: SNL, Company Filings

**Single Unit Nuclear Plants are quite high cost**

We emphasize the substantially higher cost structure of these units. NEI emphasized many of these are already quite efficient and are unlikely to benefit disproportionately from wider industry reductions.

**Figure 3: Single-unit sites are much higher than their peers**

Source: NEI
Generating costs are coming down… but fast enough? And what will it cost?

After peaking at ~$40/MWh in 2012, 2015 average costs of ~$35-36/MWh mark the third year of cost declines and is marked by significant dichotomy between single (~$44/MWh) and Multi ($33/MWh) unit plants. Capex of ~$6.25 in 2015 was down year over year and notably below the $8.7B spent in 2012. Further, despite 3% reduction in total generating costs in the last 5 years, 26% real increase since 2002 suggests substantial room for improvement particularly as some plants prepare to make the trip from 40 to 60 years. Cyclical capex needs are moderating somewhat but substantial further efficiency improvements are needed in the medium term.

Fukushima and Lifecycle Extension Capex at an end? More capex risks

While NEI focused on capex cycle winding down due in large part to 2010/2011 investments and Fukushima compliance in recent years, we remain skeptical on the ability of many plants to structurally maintain these reductions throughout. The last decade has illustrated the risks of operating around key developments in the industry and corresponding meaningful capex risks in response to global developments.

Pricing trends on fuel: heading lower.

A shift either direction could easily offset 3% annual cost deflation over the last 5 years. On the other hand, 5 year price hedges rolling off could give cost reduction efforts a boost in 2016 assuming uranium prices remain depressed. Lastly, Fukushima showed distinct evidence of black swan risk for the industry and we think renewed focus on nuclear safety in the face of geopolitical threats could conceivably cause a situation where the industry is forced to adopt more stringent and costly security measures (which could affect both O&M and Capex needs).

Figure 4: Spot uranium prices – coming back down off lows

Source: TradeTech, Bloomberg
NEI's Call on Nuclear Cost Deflation: Conference Call Transcript

The following are highlights from our call with the Nuclear Energy Institute (NEI) Maria Korsnick, and Tony Pietrangelo.

Replay Information (available until 4/13):

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Toll: +1 402 977 9140
Passcode: 21808652

Maria Korsnick

Thank you, Julien.

We appreciate the opportunity to share our perspective on cost and performance trends in the nuclear industry, and to give your clients our view of the outlook.

Here is what we plan to cover today.

We’ll start with industry performance, then summarize for you the work underway to offset the economic pressure on some nuclear plants – by increasing revenue, improving efficiency and reducing costs.

Figure 5:

Once again in 2015, U.S. nuclear plant performance was outstanding – a tribute to the dedicated men and women who operate and maintain the 99 nuclear reactors that produce approximately 20 percent of the nation’s electricity, and two-thirds of our carbon-free electricity.

The fleet’s average capacity factor was just over 92 percent – a record.
Nuclear generation for the year was 798 billion kilowatt-hours – a bit higher than 2014, even though we had one less plant.

Nuclear plants in competitive markets face the cumulative impact of several negative forces, including:

- Sustained low natural gas prices, which are suppressing prices in wholesale power markets.
- Relatively low growth – and in some markets, no growth – in electricity demand.
- Federal and state mandates for renewable generation, which suppress prices, particularly during off-peak hours. Some parts of Illinois see negative prices for as much as 10-11 percent of the off-peak hours.
- Transmission constraints, which require power plants to pay a congestion charge to move their power onto the grid. Some nuclear plants at particularly congested points on the grid see congestion charges of $5-10 per megawatt-hour.
- Market designs that do not compensate the baseload nuclear plants for the value they provide to the grid, and market policies and practices that tend to suppress prices.

Given the large number of factors causing the stress, it’s no surprise that there’s no single, simple solution.

There is nothing we can do about low natural gas prices or low growth in electricity demand, so the industry is committing substantial resources to things we can control – correcting weaknesses in competitive electricity markets; valuing the attributes of nuclear plants that are not recognized, or not fully recognized, by the markets, particularly the carbon-free attribute; and a major new industry initiative to drive greater efficiency at our plants and reduce costs.

Our goal is obviously to minimize the number of nuclear plants shut down because the markets do not recognize their value.

Like most industries, the nuclear energy industry experiences periods of economic stress. Ten U.S. nuclear reactors shut down during the 1990s, and the industry emerged from that down cycle more productive and more profitable. The long-term fundamentals suggest the same will happen again.
Just to summarize: In the last three years, companies have shut down – or announced their intent to shut down – eight nuclear reactors, about 6,300 megawatts of generating capacity.

In terms of carbon abatement, these eight reactors avoid about 35 million tons a year – more than eight percent of the Clean Power Plan’s 2030 target reduction, so you can see the CO2 meter is moving in the wrong direction and the first compliance period under the Clean Power Plan hasn’t even started.

Of these eight reactors, four of them – Kewaunee, Vermont Yankee, Pilgrim and FitzPatrick – have closed, or will close, due to market issues.

And, as you know, there are other nuclear stations at risk in the competitive markets.
We are convinced that there was nothing wrong with any of the nuclear plants that have shut down for market-related reasons, or any of those at risk. Kewaunee, Vermont Yankee and others were all solid performers – highly reliable plants with high capacity factors and relatively low generating costs. The nuclear plants at risk in western PJM are producing in the low-$30-per-megawatt-hour range.

For those plants, there’s clearly something wrong with the markets in which they’re operating. They’re not structured to recognize the value of the resources in place. They’re not operated so that all costs are reflected in prices. They’re distorted by out-of-market revenues and mandates.

As we consider solutions to this set of problems, this leads us back to simple economic principles.

Goods and services will only be produced in a competitive market when they are priced and valued in the market. There are no free goods.

We cannot continue to think of electricity as an undifferentiated bulk commodity. Every kilowatt-hour of electricity on the grid has a unique set of attributes, depending on how it is produced.

Every kilowatt-hour of electricity on the grid has a distinct pedigree. If we don’t identify the attributes, and value them in our market design and market policies, then companies will stop providing those attributes – and that, of course, is what’s happening.

On this slide, you can see the attributes of nuclear energy. It’s pretty clear that nuclear electricity is a premium product. As you go through this list of attributes, you can also see that a number of them must be recognized and valued whether the plant is in a regulated state or in an organized market.
As I said, if we do not recognize and value these attributes – in both the competitive markets and the regulated markets – we will continue to lose the valuable baseload generating capacity that drives our four-trillion-kilowatt-hour-a-year economy 24-by-7.

Figure 8:

We are seeing some progress in reforming market structures and designs that do not compensate the baseload nuclear plants for the value they provide to the grid, and changing market policies and practices that tend to suppress prices.

The industry is pursuing reforms in both capacity markets and energy markets, and there has been significant movement on the part of the Federal Energy Regulatory Commission (FERC) and a number of Regional Transmission Organizations to address some of the underlying problems.

Last year, for example, FERC approved a proposal from PJM to reform its capacity market to provide additional compensation to generating resources – like nuclear power plants – capable of sustained, predictable operation. These so-called Capacity Performance resources are expected to be available and capable of providing energy and reserves when needed, and will face substantial penalties if they are not.

**PJM held its first capacity auction – for the 2018-2019 delivery year – in August 2015 and two transitional auctions in September. In all three auctions, the Capacity Performance resources cleared at significantly higher prices than previous auctions that did not include a Capacity Performance product.** The New England ISO has established a similar mechanism to reward higher performance and penalize poor performance.

In the energy markets where baseload plants generate most of their revenue, accurate price formation is absolutely essential.
Price formation issues are complicated, but the goal is relatively simple: Ensure that all costs necessary to operate the system are reflected in locational marginal prices (or LMPs).

Transparent, accurate price formation breaks down when grid operators take actions that deviate from least-cost dispatch.

In such cases, system operators manually dispatch a resource that is needed to resolve a constraint, or address a reliability concern, but those costs do not show up in the clearing price. The RTOs provide make-whole payments, or “uplift” payments, to those resources. And there are other actions that lead to uplift: failure to accurately reflect start-up and no-load costs in clearing prices and artificially low offer caps that may at times prevent all costs from being included in clearing prices.

This uplift tends to suppress price signals and inhibit accurate price formation.

**Figure 9:**

![Movement on Energy Market Reforms](image)

FERC has developed an exhaustive record on price formation issues, starting with a series of technical conferences in late 2014.

Last September, FERC took a first step, with a Notice of Proposed Rulemaking (NOPR) that would revise its regulations governing how the Regional Transmission Organizations set prices in the energy markets.

FERC’s first step – the NOPR last September addressing settlement intervals and shortage pricing – proposed two changes.

The first would require that each RTO settle energy transactions in its real-time markets at the same time interval it dispatches energy. Any misalignment between dispatch and settlement intervals may distort the price signal.

The second change would require that RTOs trigger shortage pricing for any dispatch interval during which a shortage occurs. There’s an obvious problem if
there’s a delay between the time when a system experiences a shortage and the time when prices reflect the shortage condition.

Although welcome, the two changes FERC proposed last September could be described as “low-hanging fruit.” These are issues that influence the real-time market, but revenue to the baseload nuclear units is determined in the day-ahead market. So closing the gap between day-ahead and real-time markets is also essential.

In addition, the FERC initiated another NOPR that would change the policy on offer caps, and would allow the RTOs to use the higher of $1,000 per megawatt-hour or a cost-based offer.

Finally, the agency issued an order directing the RTOs to report back on how they manage various price formation issues, including uplift. Those reports were filed in early March. With these filings (coupled with the technical conferences and other information compiled in the price formation proceedings), it is now time for the FERC to take action to require the RTO/ISOs to implement measure that will ensure that all costs to operate the system are included in clearing prices.

While some progress is being made on these price formation issues, meaningful reform will take time and may not be sufficient to help many nuclear facilities. In addition, these price formation efforts do not address market distortions caused by federal and state subsidies to other sources of electricity. As a result, even if the FERC ensures that all costs of operating the system are fully incorporated into energy market clearing prices, those clearing prices may still be insufficient to preserve nuclear plants if out-of-market revenues to other sources continue to suppress prices.

In addition to policy changes at the federal and regional level, a number of cases – Illinois, Ohio, New York – we see the states taking steps to implement policies that would preserve existing nuclear plants.

The policy prescription varies from state to state, as each state tailors the solution to its unique circumstances. In Ohio, it is a power purchase agreement; in Illinois, a low-carbon portfolio standard; in New York, a Clean Energy Standard.

The states are motivated, of course, by the consequences of closing down a nuclear plant permanently – loss of high-paying jobs, loss of economic value, loss of relatively low-cost carbon-free electricity that will be essential to any program that makes meaningful reductions in CO2 emissions.

Programs like these can provide helpful support for some existing nuclear plants. Since these programs impact wholesale electricity markets, however, FERC also has jurisdiction. FERC support for such programs will be critical, but it’s not yet clear whether that support exists.

Now let me turn to Tony Pietrangelo, NEI’s chief nuclear officer, to discuss the industry’s cost structure, and what we are doing to drive greater efficiency across the fleet.
Tony Pietrangelo:

Thanks, Maria. Good afternoon, everyone.

Let me start with a quick summary of cost performance.

We’re encouraged that the trends here are in the right direction.

U.S. nuclear plants operated in the $35 to $36 per megawatt-hour range on average, the third year of declining cost since the peak of about $40 per megawatt-hour in 2012.

That is total generating cost, which includes fuel, operating and maintenance costs, and capital.

Three-quarters of nuclear electricity in the U.S. comes from plants with multiple reactors on site. **In 2015, the total generating cost at multi-unit plants was $32.90 per megawatt-hour, compared to $44.52 for single-unit plants.**

We invested $6.25 billion in the plants in 2015, a little lower than 2014, and a significant decrease from the $8.7 billion in capex in 2012.

Figure 10:

Here you can see the trends in costs going back to 2002, broken down by fuel, capital and O&M, in 2015 dollars per megawatt-hour.
Over the last five years, we’ve actually seen cost deflation overall – a 3 percent reduction in total generating cost.

But you can see we experienced a major increase in capex between 2002 and 2015. This was the product of several factors – replacement of major components like steam generators and reactor vessel heads as companies prepared plants to operate past 40 years; power uprates to increase output; and regulatory compliance.

Capex is cyclical. We put a large number of nuclear plants in service in a relatively short period of time, so we should expect to see periodic surges in capex as major components and equipment are replaced and upgraded.

For several years, we’ve been expecting to see some moderation in capital spending, and we believe we saw the first signs of that in 2013, 2014 and 2015.

For example, capital investment in power uprates peaked at $2.5 billion in 2012 but declined to $315 million in 2014.

Capex for compliance with the Nuclear Regulatory Commission’s requirements was about one-third of total capex in 2014.

Capital spending to meet regulatory requirements was around $1 billion a year in 2007 and 2008, before reaching a peak of almost $2 billion in 2014. This increase began with significant investments in security post-9/11, followed by expenditures for Fukushima response, which totaled $1 billion in 2014.

As we complete the Fukushima-related safety enhancements – and we expect to be substantially complete with Fukushima response by the end of the year – we expect regulatory capex to moderate substantially, and revert toward the 2007-2008 levels.
In parallel with our efforts to generate additional revenue and increase asset value through the market reforms that Maria discussed, we have also launched an industrywide program to drive greater efficiency across the industry.

We call this initiative “Delivering the Nuclear Promise – Advancing Safety, Reliability and Economic Performance.”

We are analyzing our operations to determine where we can improve efficiency. This multi-year program is identifying opportunities for efficiency measures, cost reductions and technology solutions that could be implemented industrywide to advance safety and improve operations.

We will always maintain our commitment to safety and reliability. In fact, I’m confident that safety will continue to improve, because our staff will be focused on high-priority work and not distracted by less significant issues.

The program was developed by chief nuclear officers from across the industry. It will also leverage the expertise of industry organizations, including NEI, the Institute of Nuclear Power Operations and the Electric Power Research Institute.

Teams of industry experts have identified initial areas where cost efficiencies or process improvements may be gained. The pace and scope of implementation at each nuclear power plant site will be determined by the company that owns and operates it.

The goal is to achieve significant and sustainable cost savings by 2018 and beyond. We set ourselves a target of 30-percent cost reduction across the fleet from a 2012 baseline of $40 per megawatt-hour.

But I encourage you not to focus too much on arithmetical precision here, as we’ve seen some try to do. We established these goals to be deliberately aggressive and aspirational – to signal to the industry that we are not looking for minor incremental improvements to the status quo, but more revolutionary, game-changing innovations and improvements.

Obviously, not all plants can achieve a 30-percent cost reduction. Nuclear plants operating in the first and second quartile in the low-30-dollar-per-megawatt-hour range are about as efficient as it is possible to get.

Nonetheless, we think it’s possible to extract several billion dollars from our cost structure industrywide going forward.

As I think you know, our focus for the last several decades was on safety and reliability, with less focus on efficiency. This new initiative simply assigns efficiency the same priority as safety and reliability.

Step one in the plan was to analyze the cost data, to understand what is driving operating costs, so that we could identify opportunities to improve.

We could see clearly where the major cost increases have occurred, and that gave us signposts as we charted a path toward greater efficiency.

For example, we could see that four activities – work management planning and execution, corrective action, and training – were major cost drivers, and accounted for 50 percent of the industry’s operating budget.
Based on analysis of the cost drivers, we created teams – each led by a CNO – to develop specific improvement opportunities in the 10 areas shown on the slide.

That was last October. By year’s end, the teams had produced over 180 ideas that were successively reviewed and refined until approximately 50 ideas were identified for pursuit in 2016.

*Figure 12:*

![First Improvement Opportunities Have Been Identified](image)

The teams are developing specific improvement opportunities. These will be distributed via new NEI Efficiency Bulletins, and will be endorsed by INPO to assure adherence to our highest safety and reliability standards. So far this year, we’ve distributed 10 efficiency bulletins to the industry.

I mentioned earlier that we expect to see moderation in regulatory compliance costs going forward. We have invested heavily over the last decade or more – first on improved security measures, more recently on upgrades to address lessons learned from the Fukushima accident.

Essentially all U.S. reactors have implemented the NRC’s post-Fukushima safety requirements ahead of the NRC’s schedule.

The industry has managed its response to Fukushima while avoiding costly new requirements that would have provided little benefit. For example, the NRC decided against a requirement to install external reactor containment vent filters, an avoided cost of at least $1.6 billion for no added safety benefit.

Remember that the root cause of the Fukushima accident was lack of electric power and lack of water to cool the reactor core and the used fuel pools.

So the centerpiece of the U.S. industry’s response to Fukushima is our strategy called FLEX. The FLEX approach adds portable equipment – pumps, generators and the like – at diverse locations around the plant site. The strategy requires that the plant sites obtain, prepare and maintain portable equipment that can connect
to a variety of locations. This ensures that we can always maintain the flow of cooling water and provide a continuous supply of electricity.

In addition to having this equipment pre-staged at all 61 sites, we operate two centers for additional critical equipment. The centers are located near Memphis and Phoenix and are capable of delivering supplemental emergency equipment to any of America’s nuclear plants within 24 hours. This is yet another layer of equipment that will enable them to manage an extended loss of electrical power and/or cooling water supply.

We’re excited about what we can achieve as an industry, but we’re also encouraged by what we see at the Nuclear Regulatory Commission.

In parallel with our efforts to improve efficiency, we are seeing progress on an initiative designed to address the cumulative impact of NRC regulatory actions.

This agency has grown over the years – from approximately 3,000 employees in 2004 to approximately 4,000 in 2014, a 25-percent increase. Likewise, the NRC budget: from $626 million to $1 billion, a 60-percent increase, over the same 10-year period.

The industry will always spend what is necessary to ensure safety and reliability. But over the years, the number of regulatory requirements continues to increase – including some 47 rulemaking proposals now under consideration. The companies that operate nuclear plants must devote resources to comply with these requirements, some of which do little to enhance safety.

NEI has recommended changes in the NRC’s process of evaluating proposed regulatory actions of all types, including termination of rulemakings that would impose significant cost with little or no safety or security benefit.

Under the leadership of NRC Chairman Stephen Burns, the NRC is implementing an initiative called Project Aim, designed to provide recommendations for improving performance; to develop realistic projections of the workload for the agency five years out, and to make recommendations for agency budget and workforce to guide “right-sizing” of the agency.

And we’re seeing the first fruits of this effort. In 2015, the commission directed the staff to set priorities for regulatory actions. The NRC terminated a number of activities last year, generally because the costs and resources required were not commensurate with the benefits.

Let me stop there, Julien. Maria and I would be happy to answer any questions.

**Julien Dumoulin Smith**: Great. Excellent. Well I appreciate it, and let me kick it off here. And actually let me also take a second to remind listeners, feel free to send me an email. We’ve got a few of them coming in, but let me remind you all. And then if not, we’ll take a few questions from the line in just a little bit.

So again, thank you all three for taking the time. Let me cut back here to the trajectory of the costs in the industry. You kind of alluded to it a little bit earlier, peaking out back in that - call it that 2012 time frame. I suppose there’s a 30% goal in the industry off of that $40 a megawatt number.

And if I look at your disclosures, that kind of brings you back to where you were in the 2002 time frame. A, is that a fair way to characterize it? And B, how realistic is that, and when do you get there? Do you follow?
Tony Pietrangelo: Yes. So as I said earlier, the 30% was a number we selected to drive our effort as an aspirational number, such that we weren’t just tweaking little processes. We’re using a more revolutionary approach in attacking these processes.

We started with 2012, because that’s when we actually started a number of our activities here at NEI on the cumulative impact of regulation. So that’s where we saw the peak. We’ve seen the O&M costs drop from 2012 at 40, already to 35.50 in 2015. So that’s already a substantial improvement.

And we think the majority of that comes from a reduction in CapEx. As we stated during the presentation, we’re not installing steam generators anymore or reactor vessel heads. The power uprate activity’s over. The Fukushima spend is largely over. So we’ve already seen a reduction in that.

We also see a continuing reduction in the cost of fuel over the next several years, due to the fact that there’s lower demand and a plethora of uranium around.

So really what we’re trying to attain with Delivering the Nuclear Promise is the delta between $28, which would be the 30% reduction, from the reductions we’ve already seen. And that comes out to about $3 per megawatt hour. And that equates to about $3 billion in costs that we’re trying to remove from the industry-wide cost structure.

So we think that is feasible. As we said, it’s going to cut differently for different plants. There are some in the top decile that are already at $28 per megawatt hour. And there are others that are substantially over that.

So some of these efficiencies will be implemented differently. Some plants have already implemented some of the efficiency bulletins that we’ve issued. So that’s where that component that reflects part of the 30% that Delivering the Nuclear Promise is aimed at comes from.

Julien Dumoulin Smith: If I could push you a little further, is there kind of an average goal post, at which point you look at getting that average there? I mean obviously each plant is discrete and specific to where it is in its spending cycle. But is there kind of a good way to think about, in general, when you get there, and especially the cadence of that?

I would imagine if you’d begun implementing these things, you’re targeting kind of the low-hanging fruit earlier. The pace of that deceleration’s probably front-end loaded. But I don’t want to put words in your mouth. I’d just be curious if you could talk to those...

Tony Pietrangelo: Yeah, we’re simply going to use the Electric Utility Cost Group data to track progress on this. And we expect continued reductions in the industry average O&M cost and total generating cost.

Maria Korsnick: Yeah, and in fact when we say things like $28 a megawatt hour, that’s what we’re tracking against, as Tony said. It’s the EUCG industry average number that we’re looking at.

And, you know, as you said, in terms of pace and cadence, there are some more challenging things that we’re working through that’ll take, you know,
many more months to lay the groundwork for while we’re issuing bulletins, if you will, on some of the lower-hanging fruit, as Tony said, to kind of get folks, you know, out there and working.

I would also just share, the journey that we’re on is really key -- in other words, the industry working together, forming these teams, working on items to decide what is the most efficient way to do something.

As you know, in our industry, not only are we regulated by the Nuclear Regulatory Commission, we’re self-regulated through the Institute of Nuclear Power Operations. And as part of that self-regulation we issue a lot of rules and guidance, if you will, that direct the way that we operate today.

So if we want to change how we operate today, it’s working with that guidance, rewriting that guidance, getting that information out to the industry. So we want to be very deliberate as we, obviously, make these changes. And so part of this, I’ll say, initial effort was really getting the message out there, getting organized, you know, getting teams focused, and getting some of this work on some of this guidance redrafted.

Julien Dumoulin Smith: Got it. All right, excellent. Just a few questions coming in here. First, how do we think about the 30% in terms of the different buckets, if you will -- the capital, the O&M, the fuel? You’ve kind of begun thinking about that earlier on. But could you elaborate a little bit specifically? You know, how much of this is just the cadence of CapEx and the cyclicality in the industry, versus more sort of core O&M and fuel deflation trends?

Tony Pietrangelo: The 30% reflects the entire bucket of costs, all the total generating costs. And a fraction of that -- it’s about $3 per megawatt hour -- is the part we’re going after with Delivering the Nuclear Promise.

Maria Korsnick: So when he says that that’s the part attributed to operating costs, the $3 a megawatt hour’s how we’re looking at it. And as we look at that across the industry, it’s equivalent to taking about $3 billion in O&M out of the industry on average.

Julien Dumoulin Smith: Got it. And I’d be curious on the fuel side. Obviously there’s kind of a deflationary environment out there for uranium. But I’d be curious, is there anything else that we should be thinking about in that kind of the supply chain there to help bring down costs as well?

Maria Korsnick: Yeah, I guess one thing I would just challenge, you know, there’s information you can look at for the spot price of uranium. Also realize that most plants, you know, from how they manage their fuel, are invested in some pretty long-term contracts.

So just because you see the spot price make some changes, you don’t necessarily immediately see that translated into any specific company or site reduction. It’s a good trend, I’d say, to look at and to analyze, but to appreciate that it’s not a direct sort of one-for-one, you know, reduction that you’re going to see in costs.

Julien Dumoulin Smith: Got it. That makes a lot of sense. But actually maybe to that point, given that some of these prices are likely hedged at legacy higher prices, that itself would naturally lend to a deflationary environment, right?

Tony Pietrangelo: Right.
Julien Dumoulin Smith: Great. But is there anything else structural to the supply chain that’s improving here that you can speak to?

Maria Korsnick: Yeah, so there’s more to - you know, just on the commodity price, right? For fuel, right? There’s also enrichment and fabrication prices that are, you know, sort of built into that total fuel picture. And I know the last we looked at enrichment trends, those were also on a declining trend.

So again, you know, in the direction of fuel, it looks like things are headed in the right direction. How that actually translates to any specific company or site is obviously up to how they’re hedging their fuel profile.

Julien Dumoulin Smith: Great. All right, excellent. Perhaps just keeping going here, we got another question here. What is the cycle time of the capital investment associated with - I suppose if I’m hearing the question correctly, what is the cycle time of the capital investment associated with the CapEx piece that we alluded to earlier?

I don’t know if you spoke to that directly. I mean how much of a - what’s a good normalized CapEx number as you think about, you know, the lumpiness of the CapEx cycle itself?

Tony Pietrangelo: All I can tell you at this point is that we’re doing research right now to support subsequent license renewal for our plants to go from 60 to 80 years. We’ve replaced steam generators. We’ve replaced vessel heads. The parts of the plants we’re looking at for going from 60 to 80 include the containment building, the concrete, the reactor vessel, and cabling at the plants.

Right now we don’t see any show-stoppers to going from 60 to 80. We expect the first plants to submit for second license renewal in the 2018 time frame. We continually monitor the material condition of the plants through the maintenance rule that the NRC put in place in the mid-90s.

But to specifically answer your question, I don’t think there is a number or cycle time that we can say CapEx will go up and down based on this cyclical nature. It’s a very long cycle, and we’ve gotten through that to go into the 40 to 60 period, and we don’t see any show-stoppers going from 60 to 80.

Julien Dumoulin Smith: Got it. And just practically speaking, the real investments especially across the industry for that transition to 80 probably don’t kick in for some time still, right?

Tony Pietrangelo: That’s right.

Richard Meyers: Mid-20s.

Maria Korsnick: Yeah, and also you have to look. Some of the things that Tony alluded to -- let’s just pick one, cabling, for example. You know it doesn’t mean that in one particular time frame you have to replace all the cabling at the plant, right?

So this could be something that you would say, hey, I understand that this needs to be replaced. And I might have a ten-year cable replacement plan or something like that. And you can, you know, sort of bucket it over several outages, several years, et cetera.
So even once you identify what those replacements need to be, for things like steam generators, you know, that was sort of one bulky, large investment. It happens in one outage. It’s one big piece of equipment. For license renewal and aging management programs, it doesn’t necessarily mean that they’ll be in that same vein.

Tony Pietrangelo: Right.

Julien Dumoulin Smith: Got it. Excellent. Another question coming in here. A little bit different angle here, but could you speak to what’s involved, from a cost perspective, in shutting down plants under the three strategies NRC offers -- DECON, SAFSTOR, or ENTOMB?

I suppose the preface of the question - NRC points to 300 to 400 million on their decommissioning site. But, for instance, Vermont Yankee was north of a billion dollars. Any thoughts, comments, on that specific side of cost, and specifically kind of containing costs?

Maria Korsnick: Well I guess I’ll start, then, Tony, I’ll hand it to you. In terms of decommissioning, there’s obviously, you know, a variety of menus, if you will, that a site or a company can take. You can go down the path of, you know, sort of fully decommissioning an asset, you know, right now today going through the decontamination and removing of equipment, et cetera.

There’s also what you mentioned which was SAFSTOR, which is, you know, you get the plant into a specific condition, and then you actually leave it in that condition for a number of years until you want to fully decontaminate and decommission the site. So there’s a variety of options that are provided. And obviously depending on those options, a very different financial profile.

Just I’ll share with you sort of why would you pick a SAFSTOR option. I’ll just give you a hypothetical example. You could have a fleet, for example, and you might have plants that are relatively close together, but at two different sites. And you might have one that has an end-of-life, you know, a few years, let’s say even five years different than, say, another site.

So as a company, you would look at that and say, hey, there’s a lot of synergy for me. I could hire one decommissioning, you know, company or resource, and I could do sort of both my plants in a similar time frame. There’s a lot of, you know, sort of synergy and purpose in that.

So that’s the way that sort of some fleets and companies might be looking at it, that it’s not just a one-site conversation, but rather a broader conversation. And you’d be looking to optimize that decommissioning site for your entire fleet.

Julien Dumoulin Smith: Makes sense. Can I continue here a little bit back to what we were talking about earlier? On the CapEx trajectory, as you think about those specific items, the rolling off, anything else outside of the subsequent relicensing process that would kick that back up, or obviously drive things down in kind of a structural sense one way or another?

Tony Pietrangelo: Not that we see at this point, Julien.

Julien Dumoulin Smith: Okay. All right, great. Separate question coming in on the capacity factors and the refueling outages, and the refueling outage days. I suppose you’ve seen an improving trend of late. I’d be curious how much better
can the refueling cycle fundamentally get, right? Obviously we’ve seen that it’s kind of like a secular trend in the industry. Is there still more to go on this specific angle?

**Maria Korsnick:** Well I don’t know. We did some benchmarking over in Europe a number of years ago, and I think somebody was having a refueling outage that was 14 days long. They had - it might have even been less than 14 days.

They had a very significant sort of replacement and swap out mentality. Instead of working on any equipment, essentially you really just removed it and put in a new piece. And you refurbed all that equipment while the plant was operating.

So I guess I would just challenge our thinking. You know, is there sort of more to be had? You know, once you start to get in the teens, I would say that it’s harder and harder. But there’s obviously, you know, more ways to continue to look at it, and maybe different ways than we do it.

We do a lot of swap-outs today, but I’d say we do a mixture of swapping out equipment, as well as refurbishing some equipment and reinstalling it in the same outage.

But the other challenge I would propose is, you know, it doesn’t always mean that shorter’s better. You know, depending on what market that you’re operating on, and depending on when your outage is, as we talked about, in fact, the market not appropriately valuing, you know, some of the resource, in fact you could find yourself, in some of the shoulder months, it might be okay to have a longer outage.

It might be a least costly to have a longer outage, because there’s (unintelligible) people for overtime and weekends and Sunday work and holiday premiums and that kind of thing, if in fact the market for your commodity, you know, isn’t very strong.

So I guess I would just challenge the thinking that it’s not always the case that shorter is better, and throwing a lot of money at the outage to get it shorter is the best business approach.

**Julien Dumoulin Smith:** Got it. Excellent. That’s great. Next question coming in. I suppose when you look at the single-unit sites, obviously they stand out, in your slides, you know, disproportionately higher cost. Is there anything that can be done there to bring those down? I mean when you think about the options that you’ve been pursuing in terms of CapEx reductions, perhaps not pursuing subsequent relicensing would keep costs contained? I’d just be curious.

**Tony Pietrangelo:** There’s two things you can do -- increase the numerator or reduce the denominator, right? So power uprates, we don’t see a lot of that going forward, so that takes care of the numerator. And we’re working on the denominator in terms of making ourselves more efficient, both at multi-unit sites and single-unit sites. So, I mean, that’s what you can do practically.

Not looking at subsequent license renewal? I’ll be frank. Right now I don’t think we have a good idea of what additional spending would be necessary to go
from 60 to 80. There will be some, but I’m not sure that makes the single-unit plant, you know, any less efficient now.

Maria Korsnick: Yeah, as Tony said - and we might have had the denominator and the numerator swapped in that analysis. But I’ll just share with you there’s some small plants, for example, that if you just looked at the cost, you would say that they are in the top quartile -- in some cases even the top decile -- of performance.

But if you look at cost per megawatt, you’re going to see that they’re in the third or fourth quartile. And it goes exactly to what Tony’s saying. From a cost perspective, they’ve actually really honed it. They’ve figured it out. They’re incredibly efficient. They just don’t have a denominator, quite frankly, that’s big enough, you know, that they can drive the cost down.

And so in some cases, too, I think we need to take a look at some of those single-unit sites, especially ones that are in a fleet, because, you know, they’re bearing the burden of some portion, depending on how you calculate it, of a corporate cost. **The reality is when you shut down that single-unit site, I really don’t think that amount of corporate goes away.**

And so you really have to look at, you know, I get it on paper. It looks like it’s this number. But the reality is the shutting down of that one plant, if it really doesn’t reduce that kind of corporate, you’re essentially paying that corporate price anyway, you know, while you’re operating this plant.

So personally I look at those with a bit of an adjustment in my mental eye, for what the cost really is that could be attributed to that plant. And I believe what you’re seeing here are generally worst case scenarios.

And, you know, as part of the Nuclear Promise that we talked about, there’s a revenue piece of this as well. And so, you know, I’d just remind us of the conversation that today we talk about energy as a bulk commodity, as opposed to, you know, really looking at that commodity and saying, hey, what pedigree does it have?

And one could imagine, you know, in the not too distant future that some of the pedigree that that single-unit site is bringing to the table, relative to reliability and carbon-free power, in fact, could be valued differently. And so again, the challenge we have is to not take a short-term decision, and instead take the long view.

Julien Dumoulin Smith: Excellent. Keeping going here, I suppose, how do you square the cost reductions against sort of the aging of the fleet itself? This is kind of a question coming in here. Obviously I would imagine that would drive a certain amount of inflation itself organically.

But have you actually observed that as these units are getting, quote/unquote, “older,” that they organically incur higher cost? Or what have you observed historically in the sector, you know, sort of independent of these discrete CapEx requirements that come up?

Maria Korsnick: Yeah, honestly I would just say from a rule of thumb, I haven’t seen that. I was a site vice president at one of the older plants, and familiar with the costs of that one versus another plant that I was responsible for that was, you know, much younger.
And, you know, I wouldn’t say that there was any sort of obvious trend. And I’d say the reason why is that in the nuclear industry, we’re pretty passionate about doing preventive maintenance. And so there’s so much ongoing. Every six months, do this. Every year, do that. Every three months, do that. We replace gaskets and pieces and parts and pumps and valves.

And so I get it. You say, well it’s an older plant. Well it might be older looking at the sign on the outside telling you when the plant started. But on the inside, it’s not so old. And so I think that’s a reason that we don’t really see the kind of trend, you know, that you’re talking about.

Now some pieces and parts that you don’t replace so much - and Tony mentioned them, like a steam generator, you know. That’s why you see that as a real bulky spend, in fact, in CapEx. The other thing would be what he mentioned and that we’ll be looking at for license renewal, and that is a cabling.

And so although there are some, you know, cable replacements, that would be a more deliberate, I’ll just say, project that would be looked at, that would be maybe outside of, let’s say, the standard preventive maintenance approach that we take.

Julien Dumoulin Smith: Got it. Excellent. And then coming back a little bit more to the policy end of things, I mean obviously getting carbon recognized, and it’s - getting the nuclear attributes in carbon recognized as the key goal, there’s state-specific efforts underway.

What states should we be paying attention to here? I mean obviously New York is the most tangible one, I supposed, in the near-term sense. But what other states, you know, merit closer scrutiny and attention as perhaps case studies here of an improving trend?

Maria Korsnick: Well, I mean, we mentioned Illinois. Obviously that’s…

Julien Dumoulin Smith: Yeah, sorry.

Maria Korsnick: …you know, a real interesting one because of the battle with, you know, some of the production tax credits, et cetera, and the subsidized wind issues that you have there in the middle part of the United States. So I think that one’s very interesting.

Those are the ones - and we’ve, of course, also mentioned Ohio, that just recently went with the power purchase agreement that affected their Davis-Besse plant.

So I think what’s real interesting about those three, Illinois and Ohio, more of a sort of clean energy standard, low-carbon standard - I think what’s going to be interesting about that is we’re going to be able to find some interesting solutions and varieties of solutions that give us an opportunity then to say, hey, this was working in Ohio - in New York, and this was working in Illinois. You know, are there other places that this would apply?

So I think it’s a good opportunity for us, if you will, to sort of try something out, and then see where we can potentially, you know, cross-pollinate that.
Julien Dumoulin Smith: Got it. Coming back once more to the cost, just trying to focus in on this a little bit more, you know, I know there’s a little bit of a hesitancy to talk about the time frame. But is there something kind of near-dated, obviously even successful somewhat, in recent periods in bringing that down, especially the last few years, ‘12 through ‘15, shall we say?

Is there anything bringing this down in particular? Or is - I’m just trying to get a sense of like the discrete, near-term outlook, ‘16, ‘17, ‘18. Anything in particular that could help bring that down in kind of a more step-wise way across the industry? I don’t know if there’s a…

Tony Pietrangelo: That’s what our effort - yeah, that’s what our efforts are aimed at in the Delivering the Nuclear Promise, as we said during the presentation. Some of the numbers that were increasing the cost have gone away. Our goal really is in the 2018 to 2020 time frame, have that - get down to that where the first quartile plants are now.

But we don’t see big capital spend in upcoming years. We do see the regulator tightening their belt. We’re trying to tighten our belt and get more efficient. And so I think all those factors play to being able to drive that number down consistently through the next couple of years.

Julien Dumoulin Smith: Indeed. Excellent. Another question coming in. Are the cost deflations and their drivers in CapEx and O&M - are there cost deflations and their drivers in CapEx and O&M consistent across different nuclear generation technology types, e.g., BWRs versus PWRs, et cetera?

Is this necessarily the case for, for instance, CANDU reactors in Canada? I know you may not necessarily be tracking that one as much, but obviously of some relevance for others out there.

Maria Korsnick: Yeah, sure. I guess I can say the items that we’re focused on, that Tony teed up in the Delivering the Nuclear Promise, would be equally applicable to, you know, to all designs in terms of the way that you operate in a nuclear industry isn’t altogether that different as we go from, you know, sort of one country to the next.

And many people, in fact, pattern their operations after the US fleet. And so as we come up with ways to operationally become more efficient, you know, there’s opportunity for those others. In fact, we’ve been asked in several different forms to share the efficiency bulletins, and we’re glad to do that, to our international folks.

So there’s nothing that we’re looking at in terms of what we’re doing that’s, you know, BWR-specific or PWR-specific, you know, in terms of design.

It’s really more of, I’d say, the administrative-type processes that we have put in place at our plants today, and ways to take sort of the layering of the many processes, and step back and redesign a much more from-scratch process than one that sort of got cobbled together. layer upon layer, of a variety of regulation over a number of years.

Julien Dumoulin Smith: Excellent. Anything else that we should be hitting on in terms of the cost trends here? I mean we’ve obviously tried to hit on the refuelling. We’ve hit on the CapEx. We’ve talked about fuel. Perhaps I haven’t asked enough
with regards to the O&M piece. I mean is there anything that we can break down there to kind of tangibly point to, here are the five or six items, if you will?

Maria Korsnick: Well the one thing I would add relative to O&M - and I know you've been scratching at time frame and, you know, what do we think. I would just share that over the next five to seven years, you know, as a nuclear industry, we do look at a relatively high retirement rate.

And really the idea behind this Delivering the Nuclear Promise, as we designed much more efficient processes, isn't necessarily that you translate that into, you know, an immediate change in who has a job today and, you know, job change, if you will.

But rather to say, hmm, if I have a process that today requires 30 people to do it, and I could redesign that process and only 20 or 25 people need to do it, well then I can manage - as my folks are retiring, I can manage that.

As I hire in their replacements, I hire them in with this new process in mind. I hire them in with this new technology in place, and that kind of thing. So I'd look at it more sort of as a continuum than I would as maybe a knee-jerk reaction to something.

Julien Dumoulin Smith: Got it. All right, that's great. Actually, you know what? I'll leave it there. It's 2:59. I'm not going to dig too far in. What else should we be hitting? I'll turn it back to you may be for closing comments, anything that you think we should have made sure we dig out of the conversation here on the cost trends; obviously a pretty impressive deflationary trend in the very near term. Anything else?

Maria Korsnick: Yeah. One of the things I guess I wanted to make clear, as Tony outlined the Delivering the Nuclear Promise, I don't want to leave the impression that it's sort of a flash-in-the-pan, and this is an initiative that we, you know, got all interested in and, you know, then it's just going to go away in a few years.

So really the design of this Delivering the Nuclear Promise was to build a new gear in the machine, if you will, and that gear is an efficiency gear. And so the Delivering the Nuclear Promise has in fact put in a process, led by chief nuclear officers, the product of any good idea that comes up is an efficiency bulletin.

NEI, the Nuclear Energy Institute, owns this efficiency bulletin process. It will go on. So it's not that that process ever goes away. This initiative has established the legacy, if you will, process of this.

So if five years from now another area catches our attention that says we need to do it better, great. We get the right people together, a chief nuclear officer in charge. We understand what rules and regulations - whether they be NRC, whether they be Institute of Nuclear Power Operations, whatever guidelines need to be adjusted, we make sure that that happens.

That's the value we're providing to the industry, so that by the time you get the bulletin, the road has already been paved. The regulation has been changed. The guidance has been rewritten. The buy-in has already occurred. And so that process, in fact, is a legacy process and will go on much beyond when this particular initiative is no longer discussed. It's a lasting footprint, if you will.
Julien Dumoulin Smith: Excellent. Well with that, it's the top of the hour, so I want to thank the whole team on your side for taking the time. I want to thank everyone for listening. And I believe - if you'd like to get in touch with them, I believe all their names are on the presentation. And if you don't have it, again feel free to send me an email. So thank you all. Have a great day. We'll talk to you soon.

Operator: And, ladies and gentlemen, that does...

Man: Thank you...

Operator: ...call for today. We thank you for your participation and have a great rest of the day, everyone. You may disconnect your line.

END
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 Integrateds. Further, IPPs face declining revenues as in the money power and gas hedges roll off. Other non-regulated risks include weather and for some, foreign currency risk, which again must be diligently accounted in the company’s risk management operations. Major external factors, which affect our valuation, are environmental risks. Environmental capex could escalate if stricter emission standards are implemented. We believe a nuclear accident or a change in the Nuclear Regulatory Commission/Environment Protection Agency regulations could have a negative impact on our estimates.

Risks for regulated utilities include the uncertainty around the composition of state regulatory Commissions, adverse regulatory changes, unfavorable weather conditions, variance from normal population growth, and changes in customer mix. Changes in macroeconomic factors will affect customer additions/subtractions and usage patterns.
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Source: UBS. Rating allocations are as of 31 December 2015.
1:Percentage of companies under coverage globally within the 12-month rating category.
2:Percentage of companies within the 12-month rating category for which investment banking (IB) services were provided within the past 12 months.
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KEY DEFINITIONS: Forecast Stock Return (FSR) is defined as expected percentage price appreciation plus gross dividend yield over the next 12 months. Market Return Assumption (MRA) is defined as the one-year local market interest rate plus 5% (a proxy for, and not a forecast of, the equity risk premium). Under Review (UR) Stocks may be flagged as UR by the analyst, indicating that the stock’s price target and/or rating are subject to possible change in the near term, usually in response to an event that may affect the investment case or valuation. Short-Term Ratings reflect the expected near-term (up to three months) performance of the stock and do not reflect any change in the fundamental view or investment case. Equity Price Targets have an investment horizon of 12 months.

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<th>Company Name</th>
<th>Reuters</th>
<th>12-month rating</th>
<th>Short-term rating</th>
<th>Price</th>
<th>Price date</th>
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<tbody>
<tr>
<td>Dominion Resources1 2 4 5 6a 6b 6c 7 16</td>
<td>D.N</td>
<td>Neutral</td>
<td>N/A</td>
<td>US$72.97</td>
<td>07 Apr 2016</td>
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<tr>
<td>Duke Energy 2 4 5 6a 6c 7 16</td>
<td>DUK.N</td>
<td>Buy</td>
<td>N/A</td>
<td>US$79.29</td>
<td>07 Apr 2016</td>
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<td>Entergy Corp.16</td>
<td>ETR.N</td>
<td>Sell</td>
<td>N/A</td>
<td>US$77.19</td>
<td>07 Apr 2016</td>
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<tr>
<td>Exelon Corp.3 6a 7 16</td>
<td>EXC.N</td>
<td>Neutral</td>
<td>N/A</td>
<td>US$34.35</td>
<td>07 Apr 2016</td>
</tr>
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<td>FirstEnergy Corp.7 16</td>
<td>FE.N</td>
<td>Neutral</td>
<td>N/A</td>
<td>US$34.76</td>
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<td>NextEra Energy 4 6a 6c 7 16</td>
<td>NEE.N</td>
<td>Buy</td>
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<td>NRG Energy Inc.7 16</td>
<td>NRG.N</td>
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<td>N/A</td>
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<td>Public Service Enterprise Group16</td>
<td>PEG.N</td>
<td>Buy</td>
<td>N/A</td>
<td>US$45.90</td>
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<td>SCANA Corp.2 4 6a 7 16</td>
<td>SCG.N</td>
<td>Neutral</td>
<td>N/A</td>
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<td>07 Apr 2016</td>
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<td>Southern Company2 4 5 6a 6c 7 16</td>
<td>SO.N</td>
<td>Sell</td>
<td>N/A</td>
<td>US$50.67</td>
<td>07 Apr 2016</td>
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<td>Talen Energy Corp.6 6a 16</td>
<td>TLN.N</td>
<td>Neutral</td>
<td>N/A</td>
<td>US$10.44</td>
<td>07 Apr 2016</td>
</tr>
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Source: UBS. All prices as of local market close.

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