US Electric Utilities and IPPs

Further Defining the Wind Repowering Opportunity [Transcript Included]

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The Twin Opportunities: Repowering (Cali) vs Refurbishing (Texas)?

We hosted our latest call with Jim Tynion III of Morgan Lewis to discuss repowering opportunities in the wind sector following the latest IRS guidance. Based on the call, Texas could be a larger opportunity than we had previously thought, as a number of turbines may reach the end of the 10-year PTC shortly yet maintain usable towers for partial refurbishment (rather than complete replacement under a repowering) in the market. Further, with contracts typically ~10-yrs in duration as well, these would likely be merchant in any event as well as having strong wind resource to benefit from improved turbine technology. California remains the clearest repowering opportunity, already underway, and we would expect to see increased announcements into the back half of the year.

IRS Guidance Provides a Solid Runway

Recent PTC extension coupled with start of construction extension IRS guidance to four years (from two years previously) should allow substantial opportunities for wind buildout through at least 2020 to capture 100% PTC level in 2016. NEE remains one of the key beneficiaries in our view with double-digit market share in legacy wind installations, which could provide at least ~$53-66M of NPV benefit in our conservative analysis. Further, other large wind owners like NEP and XEL could take advantage of wind re-development opportunities to the extent that legacy contracts are beginning to near end of life.

GE: Benefits for the vendor side as well?

Not only should the latest IRS qualification be a benefit to the developers, but all the more to the manufacturers too, seeing an ability to expedite turbine replacement and sell after-market turbine blades. We expect margins to prove disproportionate on the blade replacements, particularly should blade and generator improvements materially step-up the output (typically taller towers are necessary to accommodate the more modern, longer blades). This benefit would complement the ongoing wind boom in the sector.

What is the Market Opportunity? All Depends How Recently You Look

We note current pre-2006 (No PTC) and pre-2011 US asset base of 8.7GW and 39.6GW, respectively, provides opportunities for the entire space, although NEE's 2.5GW/7.4GW of operating assets built in the past provide one of the best opportunities in our view. Assuming only ~20% of the total pre-2011 installed base is able to be repowered economically, this would still represent ~8GW in aggregate and ~1.5GW for NEE alone. While ~2.9GW of California assets likely provide some of the best economics, 10GW in Texas remains in play given magnitude of potential PTC impact on Texas wind. We expect a number of projects are currently under evaluation and we could start to see repowering decisions within the next several months as the 2016 deadline looms. We await further clarity from the IRS on defining the Fair Market Value (FMV) definitions for qualification on the repowering and refurbishment in the coming months to help frame and analyze the opportunity. Further we look for clarity from turbine manufacturers on product offerings as well to help frame this opportunity. Given the sizable capex involved, it is unlikely for most projects.

Still Primarily a California Opportunity

As we outlined in our recent NEE note, legacy California wind assets provide some of the most interesting projects for repowering today given PPA roll off and potential doubling of capacity (as turbines are upgraded from ~750kw to 1.5MW). Our project model suggests low teens (~12%) IRRs are achievable on fully repowered assets, versus mid single digits for other regions. Palm Springs, Mohave Country Desert, and Altamont Pass areas in particular were highlighted on the call as most promising for California repowering, and we expect some of these include the lowest regulatory/repermitting risk and could be currently under evaluation for repowering potential.

Could Texas Present A Larger Opportunity?

Although 'legacy' Texas Wind assets are largely built within the last 5-10 years weighted towards more recent buildout, we see potential for a unique retrofitting opportunity in light of ITC extension potential. While capacity increases in Texas would likely not be as drastic as legacy California assets, IRS guidance around re-using assets in a wind farm (the 80/20 rule) could prove more important in regions like Texas with potential for repowering while keeping the tower and other key infrastructure in place. There appear to be substantial questions around this measurement even in the legal industry, though we expect a number of developers may push the envelope before a clear answer emerges. Further, we highlight NEE's 3.1GW of wind built before 2010, including ~900MW of pre 2006 projects.

The Race is On: Why is it Crunch Time?

Clock is ticking to qualify as many repowering opportunities as possible for full 100% PTC at year-end 2016

We emphasize prospects for repowering and refurbishment remain under critical time pressure of late as developers need to gain clarity on IRS clarifications for what *exactly* qualifies for PTC extension (exactly how the 80% is defined) as well as need to procure corresponding materials (likely turbine blades) by year-end to qualify for the 100% PTC (subsequently drops to 80% * PTC value in 2017). We wouldn't doubt substantial focus remains across the industry as developers of all flavors likely seek guidance from lawyers and input from developers (GE, Siemens, and Vestas) on refurbishing opportunities.

Be very careful: *when* did you start construction?

Among the key nuances is not triggering the start of construction for a project too early. While under the old guidance, the key was *to demonstrate continuous development efforts*, while under the new IRS guidance, the focus is simply a four-year clock on projects since their construction began. As such, developers will now need to prove in some instances that they did *not* start construction back in 2012 and 2013 for projects underway today. This could yet be clarified to allow for potentially greater latitude, as this narrower reading would seemingly run contrary to the spirit of the rules, which were initially designed to enable greater wind project development latitude.

Is this truly a novel development? Repowering Guidance has precedents elsewhere.

While the IRS had never formally delineated the opportunity for repowering or refurbishing assets to re-qualify for tax credits, the 80% threshold value of asset replacement would appear to come from other industries where the IRS in the past has had to dictate requalification for tax credits as well. The clarification in many

respects is a pre-emptive effort to address what were likely obvious questions from legacy developers.

Repowering: Convenient Solution to Contract Expiration?

Among the key points we continue to come across in our industry conversations is the need to find an adequate solution on how to extend contracts and PPAs coming to maturity. Allowing deals to simply roll off into a merchant power and REC solution would likely appear unpalatable to renewable asset owners who typically market their business profile around the relative certainty provided from the long-term nature of PPAs. We see the ability to potentially re-sign PPAs under the context of a repowering as a convenient solution.

Who to Track?

NEE: Focused on 'Refurbishing' Wind Farms *too*

In an effort to distinguish on development opportunities under evaluation, we emphasize NEE is in the first instance pursuing the repowering of its existing assets in California as well as potentially in Texas (in which case the turbine would entirely be replaced), but is also evaluating refurbishments of its existing infrastructure. This would likely involve the replacement of principally wind turbines and potentially selective other working parts. We emphasize this is likely to be among the more scrutinized elements around meeting adequate 80% of capital value replacement to meet thresholds to re-qualify the turbines for PTCs. If successful this would appear a substantially greater opportunity after initial 10-year period. We expect improved turbine blades could be substantially more widespread and likely much more dependent on ability to requalify the site. We emphasize the depreciated value of the site alongside modest PPA revenues could well make the case for an 80% deal to qualify.

In contrast to NEE, mgmt at AGR noted (at the AGA conference) that they do not see an opportunity to repower – or at least are not aware of any.

XEL: Repowering is a Real Potential – Buying out Existing PPAs?

Management was quite clear (at the AGA conference) in evaluating prospects to effectively 'buy-out' existing PPAs that are nearing maturity and are beyond their PTC life. This would be 'upside' to their 'upside' case via acquisitive growth achieved at what would likely be ratebased at ~acquisition cost. The company indicates the ideal would be to buy these legacy wind assets in an effort to fully repower them (entirely replace the existing towers, blades, etc), rather than simply refurbishing them as NEE is looking to do in some instances (with new blades to add incremental efficiency). The question on acquiring assets is how commissions would respond to continued consolidation into utilities' assets that had been purposefully initiated (PPA'd) with independent entities. This trend further emphasizes the natural leaning towards eventual utility asset generation ownership already exhibited by Gas IPPs in regulated markets irrespective of the forced upfront contracting with independent entities imposed by regulators as part of a competitive IRP process for new assets.

XEL's latest disclosures indicate that:

- The NSP system acquires the majority of its wind energy from more than 120 PPAs with facilities ranging from 1 MW to 200 MW totalling approximately 2,210 MW at YE2015. Average cost per MWh under contracts was $42 and $41 for 2015 and 2014, respectively.

- PSCo also acquires the majority of its wind energy from 19 Colorado PPAs ranging from 2 MW to 300 MW totalling 2,560 MW at YE2015. Average cost per MWh under contracts was $42 and $45 for 2015 and 2014, respectively.
- SPS acquires its wind energy from 37 IPP contracts and Qualified Facility (QF) contracts, primarily located in the Texas Panhandle and New Mexico ranging from <2 MW to 250 MW totalling more than 1,800 MW at YE2015. Average cost per MWh under contracts was $24 and $26 for 2015 and 2014, respectively.

Framing the Opportunity

Repowering Potential: How to Qualify?

The value of new wind equipment must be 4X the retained value on a turbine by turbine basis (80% of new project); however, turbines can be grouped together on project sites for the 5% test (so all retrofitted turbines can qualify if aggregate spend at a wind farm meets the 5% threshold for PTC qualification). While this specific angle of qualifying 80% of assets as new has driven substantial attention from stakeholders from a legal perspective, we believe the bigger issue remains whether economics can be proved out for improved capacity factors with new turbines at existing sites.

Capex savings on the repowering appears quite modest.

Savings on the total costs are not the driver of repowering

We emphasize in nearly all cases, the entire turbines and blades would likely need to be replaced to accommodate the substantially taller towers, longer blades, and in turn, new cabling/interconnections to accommodate greater MW capacity output. As such, we see the capex savings on a repowering as rather modest, with the opportunity principally tied to expanding the capacity (MWs) as well as Capacity Factor (hours dispatched) at a given site – all under a new and extended PPA.

Some Background: IRS Guidance details

Safe harbour extended to 4 years from 2 years

Acts as de-facto *further* 2-year extension of PTCs.

On May 5 the IRS issued guidance effectively allowing a four-year runway to qualify for the PTC without having to prove that the work was continuous (up from the prior two years afforded to qualify for the safe harbour), as long as projects have 'significant' physical work started or 5% of project cost incurred (including turbines with a 3.5 month leeway period to take delivery – relevant if ordered at year end).

Looking more specifically at the key areas:

NEE management has emphasized the opportunity largely revolves around its Texas and California portfolios:

California: We note development activities appear to be accelerated in California (both in the North as well as Southern regions), where the oldest assets are presently installed and PPAs are rolling off sooner. We note assets here are typically <1MW and could garner substantially improved capacity factors. Further, given the bifurcated market structure in the state in which existing and new renewables compete in distinctly different procurement processes, the repowering avenue should enable NEE to tap into the more lucrative opportunity for further MWs. Further, with a focus in the state on contracting for further renewables to achieve its 50% by 2030 RPS target, the wind offers an alternative to 'just' more

solar that has effectively been the default in recent years. We estimate the price on these repowered projects would need to be in the ~$50/MWh range in order to be competitive with solar.

Texas: The opportunity in this state is principally due to the fact that NEE (and many others) built many of the assets here using 10-year hedges (coincident with the expiration of the PTC). As such there is no risk of 'losing' an above-market contract by repowering the asset; rather, the focus is principally around whether a substantial improvement in capacity factors can be garnered, as many of the best wind resource sites can be found across the state. While NEE had originally hedged these wind assets at ~2007 gas prices for a 10-year period, the company has since substantially expanded contract coverage for a protracted further period (rather than selling down the projects outright to reduce merchant volatility). We see this decision to hold onto the assets despite mgmt's wider more bearish view on Texas power prices as indicative of its confidence in the repowering opportunities. Lastly, because NEE employed hedges/financial swaps in hedging out its power in Texas (rather than direct PPA with a counterparty), the positions are not specific to whether the wind assets run through the course of the repowering.

In both instances (CA & TX), NEE is looking at these assets because they are largely unburdened by existing PPAs or lingering project debt/obligations. As such, they become a simple exercise of whether the renewed capex and step-up in both MWs and MWhs more than offsets the merchant economics of continued status quo operation under a largely merchant context (Energy + REC value).

Existing PPAs: Blend and Extend or Merchant on Incremental MWs?

Project-specific debt amortization, PPA rates, and ability to blend existing PPA rates will determine if repowering works

Utility counterparties to NEE's existing PPAs would *likely* seek an improved PPA rate for restruck assets; it is unclear if the company could keep old PPA rates on some of the higher performing non-upgraded assets for potential repowering. A 'blend and extend' methodology versus potentially keeping the PPA on existing capacity and selling the balance into the merchant market remains a key question. We think the former would largely be the case (in which an existing PPA with 10 of 20-years left) opts to *re-price* the deal at a savings to the utility, albeit for additional MWs. For the latter opportunity, in which incremental MWs built would be merchant, the question is whether the PPA terms of the original contract would be voided during the construction phase in which at least *some* the turbines are not operational. We emphasize again, at least the initial wave of repowering opportunities are *not* focused on assets with meaningful PPA coverage left.

We note these 'blend and extend' opportunities would largely be *beyond* those present in the initial pool under consideration by NEE in Texas and California, where there is still material PPA contract duration remaining.

Why is this blending option appealing? Bilateral negotiation adds to return

We emphasize the opportunity to 'blend and extend' is likely to drive *better return propositions for wind developers like NEE than simply responding to a typical greenfield RFP for a new project with multiple other bidders. The blend of PPA prices should enable disproportionately higher returns for the developers; there appears ample headroom to reduce PPA prices for truly legacy projects and provide an attractive overall cost to the utility.*

What about future contracting opportunities? Re-hedging now 'merchant' wind wasn't going to be easy anyways…

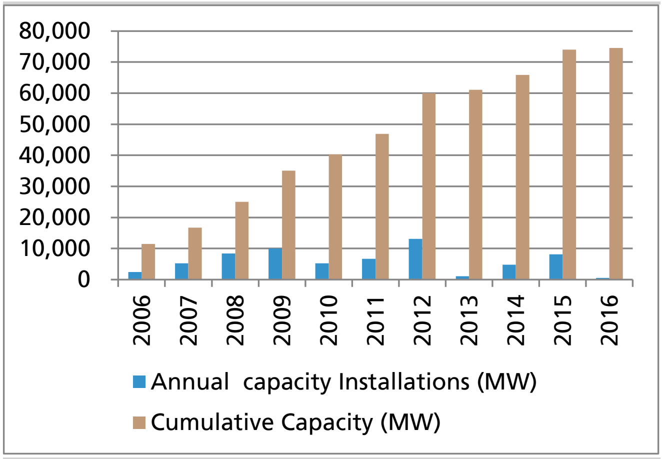
We also remind investors that much of the contracting for renewables thus far has focused on new assets. The discussion of PPA extensions is among the first serious conversations in the sector, as the assets would otherwise see compensation roll off substantially to merchant economics, particularly outside of California, where RECs (Renewable Energy Credits) garner limited value. Allowing for wind projects to be repowered and in theory eligible once more as a new entrant, should allow it to tap the same avenues for PPAs, rather than rolling to 'merchant' sale of energy and RECs.

In Context: What's the Overall Opportunity

As of 2007, there was a cumulative 15GW of wind installed which could effectively be considered for repowering, although some companies are looking at assets as late as 2010 COD (the thought there likely being 2020 in-service is the latest to qualify for 100% PTC qualification if construction begins by year-end 2016). Using our $110/kW NPV benefit value assumption, this could equate to ~$1.6B of potential NPV from wind repowering value vs greenfield development in terms of total value across the sector; we see the opportunity for repowering wind as particularly relevant as legacy projects from late last decade see the end of the PTC life. Any US based deal would effectively contemplate a 'blend and extend' on their existing PPAs, bringing them down but likely recontracting for a subsequent 20-year period.

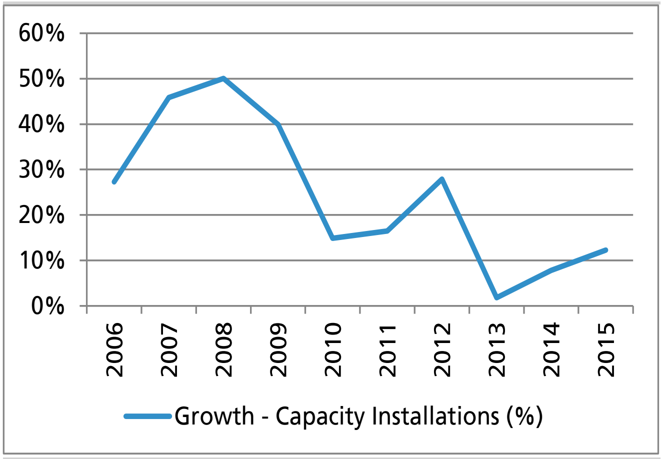
Capital spend threshold would likely be easily met in these instances since practical repowering for significant capacity factor benefits would effectively necessitate new towers (to reach higher wind regions with larger turbines), new turbines, and limited transmission spend (often no more than ~20 miles of transmission). Availability of tax equity could act as a gating factor in this instance in a rush scenario but companies like NextEra with in-house tax appetite remain best positioned to take advantage of repowering potential in our view. We expect increased focus on repowering potential and possible improvement in valuations for largely depreciated assets, although implications for PPA renegotiation remain relatively untested.

Figure 1: Wind Capacity installation (MW)



Source: AWEA

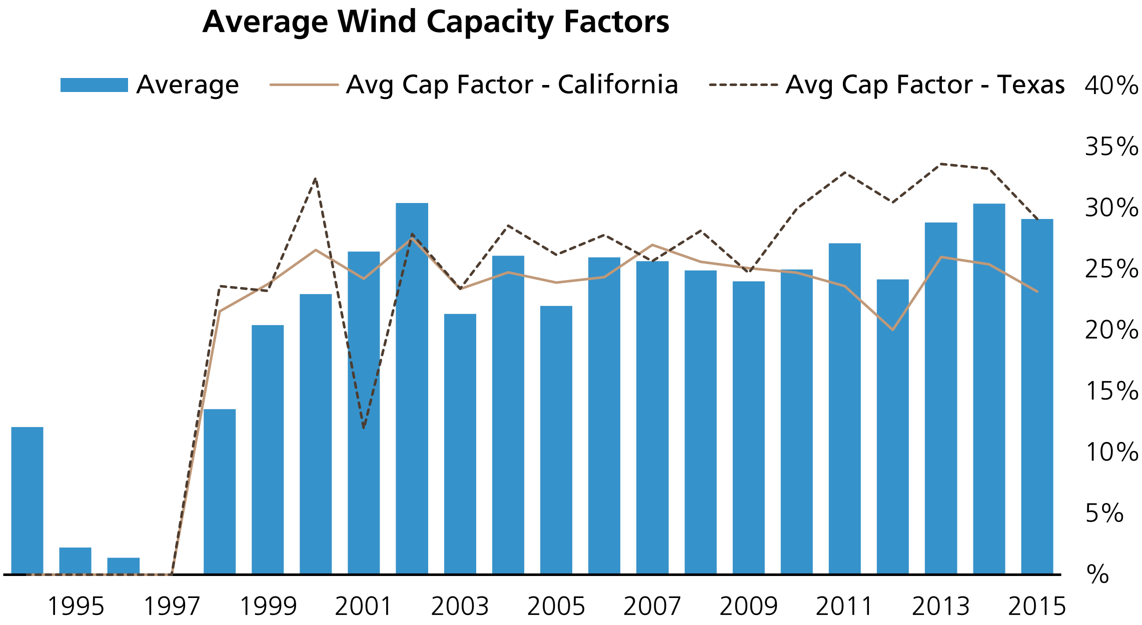
Figure 2: Wind Capacity Installation growth (%)



Source: AWEA

In aggregate, operating wind projects (equally weighted for this calculation) have largely stayed in similar range of capacity factors, although we expect this will shift as legacy projects are replaced.

Figure 3: Wind Capacity Factors Over Time – Not really shifting all that much, actually

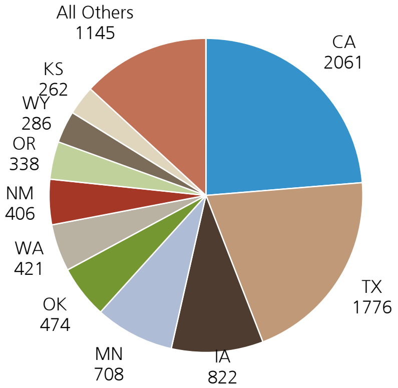


Source: SNL, UBSe

Where are the legacy projects? Texas, California, Iowa…

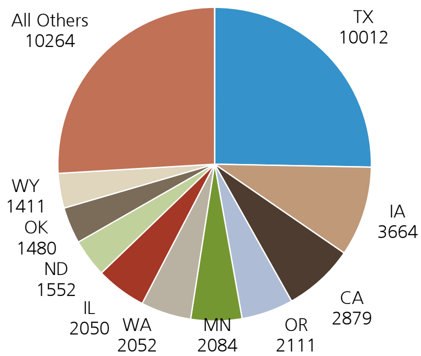
Between 2005 and 2010, significant wind buildout pushed the share of wind into Texas. Given the profile of pre-2006 wind below, we're not surprised by comments from NEE and XEL; that said, it's not clear if XEL would *own* the assets currently under PPA even if repowered.

Figure 4: Earlier than 2006 Wind (~8.7GW)



Source: SNL, UBSe Note: Units in MW

Figure 5: Earlier than 2011 Wind (39.6GW)



Source: SNL, UBSe Note: Units in MW

Conference Call on Wind Repowering [Transcript]

We present below highlights from our recent call with James Tynion at Morgan Lewis, a law firm focused on project finance as well as environmental and tax law. We have edited the transcript below for clarity. Minor grammatical changes that do not impact the meaning of content have been applied. Changes to content to clarify meaning have been underlined. What we consider to be key points have been highlighted in bold. The opinions expressed by James Tynion herein do not necessarily reflect the views and opinions of UBS. UBS accepts no responsibility for the accuracy, reliability or completeness of the information and will not be liable either directly or indirectly for any loss or damage arising out of the use of this information or any part thereof.

[Sentence deleted.]

Julien Dumoulin-Smith: Thank you and good afternoon everyone. [Sentence deleted.] We wanted to discuss IRS guidance, not just on the four year PTC extension, but what the nuance is and the repowering opportunities described therein. Joining us this afternoon is Jim Tynion, partner over at Morgan Lewis working on project finance. He's involved in a variety of different situations related to the subject and can speak to all facets not just of the IRS but the projects themselves and how to think about the repowering opportunities.

There are no slides this afternoon. [Sentence deleted.] With that, Jim, thank you for joining us this afternoon. I appreciate it.

James Tynion: Yes, thank you [Sentence deleted]. Just to frame things up for folks that are not so familiar, in December when the tax act was passed it extended and revised the tax credits that were available for renewable energy projects, wind and solar and several other technologies. In essence granting an extension of time in order to place projects in service; there was a step down over time of the amount of the 10 year PTC that's available to wind energy facilities. And there was a four-year extension of the time to place solar facilities in service.

This is a great boost to the renewable industry and happened in the end of December. What happened at the end of the last two years, there were similar extensions of the wind PTC and the question that the participants in the wind energy industry had was, if I start my project by a certain date, how much time do I have to complete the project?

Two years ago, the IRS came out with what they call a safe harbour provision whereby if someone started a project either by paying up to 5% of the expected cost of the project or by actually commencing construction of a significant nature at the site, then they would have two years to complete the project and be deemed to have continuously tried to finish the project.

What we expected in this past spring, what we expected in the industry, was that the IRS would simply roll forward that same two year period, you know, to match the extension in the, the PTC extension. But what happened was they extended out the construction period instead of two years to four years which was a pleasant surprise to most of the industry and has really given a nice ramp for project development over […] the next four years for wind projects. If the wind project commences construction by the end of this year, 2016, they're eligible for the full 100% of the full PTC credit which right now is 2.3 cents a kilowatt hour. If they start construction next year, you know, in each of the next three years, 2017, 2018, 2019, that credit goes down to 80%, 60%, etc.

Hence, there's a big push for projects to start construction this year. I think we can get into some of the nuances, what the four years means and the projects. It raises a couple of new issues with regard to when the four year period begins to count, but the good news is once it starts you have four years. That is one major piece that came out in this notice at the beginning of May and was amended a week or ten days ago, May 18th.

The other aspect has to do with the clarification on repowering. The repowering provision is something Julien was quite interested in because it seems that there are a lot of regulated electric utilities that are either owners of projects or are off-takers of projects dealing with developers who may have projects that are 10 or 20-years-old that are in very windy, well-situated locations that may benefit from simply upgrading all of the turbines, improving the efficiency economy and even all the environmental, animal, bird and bat issues with newer turbines.

Moreover, should the new facility be built on top of an old facility, it would also qualify for the PTC. The repowering rule sets forth that if a new project is built of which the total cost/portion of the old facility is no more than 20% of the value of the total new facility – that is, the old 20% plus the new 80% – then the facility would be deemed to be a new facility and the PTC would start again for that. This is going to be very helpful for projects right now, especially in the **three active areas in California** where a lot of projects were built in the late 80s and early 90s. **The Palm Springs area, up in the Mohave County high desert area, as well as in Northern California, and the Altamont Pass area; there are lots of projects there that are ripe for repowering** and we think this clarification in the rule will really push that forward. I'll pause there for a minute and see if you have a question for me now.

Julien Dumoulin-Smith: Yes, absolutely. Thank you. Coming back to the guidance that was provided, I suppose there is some further nuance that we should probably jump into. What about this concern about starting projects too early, right? Can you elaborate on how that risk manifests itself just for the four year guidance provided?

James Tynion: Yes, I think this is probably an unintended consequence of the way the guidance was worded. The wording says if a taxpayer places a facility in service by the later of, and this is kind of a complex, the later of one calendar year that's no more than four calendar years after the calendar year during which construction of the facility began, or December 31, 2016, that the facility will be considered to satisfy the continuity of safe harbour. So what that means is for the new projects, the projects that we expect to be built, that there will be a big rush during the second half of 2016 to start construction on many new wind projects.

Thus, the lenders and investors will be very careful to investigate the projects to make sure that for instance they did not start in 2012 or 2013, as the activities that were undertaken by the project on the site would not have passed the start construction test back then almost accidentally. And therefore, the four year period will have already started running. We think this, after talking to a lot of people down at the American Wind Energy Association Conference the last couple of days in New Orleans, that we're hoping this is a simple due diligence matter. We can't imagine that there are too many, if any, projects that actually will have triggered this because the definition of starting construction really talks about performing physical work of a significant nature and it's likely that preliminary studies putting up a met tower, doing some soil borings, things like that would not qualify and disqualify the project. So it's just going to add an extra due diligence item we hope and that the tax equity and lenders will get comfortable very quickly, that virtually all the projects should not have a problem with this. But it's something to look at.

Julien Dumoulin-Smith: Got it. What do you see in terms of market place activity, in terms of total quantity megawatts out there kind of taking advantage? Obviously you're kind of on the front lines of real developments. What are you hearing out there?

James Tynion: Well, the word in the market is that it's highly likely that this year could have another 8 GW (8000 MW) of new capacity added this year and probably next year that it's likely to be a sustained growth in new installations of wind projects in the United States. We think that the new renewable portfolio standards in places like Oregon and California, which have increased dramatically recently, will create this new demand. Again that's another reason for the repowering maybe; we may see a lot of that in California because they will have the greatest demand for new renewable energy.

It should get very, very busy. I think the market probably saw a very quiet first quarter of 2016, as everyone sort of sat back, caught their breath after the December extension. A lot of the solar plants that I'm aware of were put on slowdown for development in the hopes that projects would be completed in 2018 and 2019. And

development will sort of slow down a little but big projects will start to come online for solar probably more next year, 2017, 2018. This year we'll have a big push for wind energy because of the PTC stepdown. Very busy is the short answer.

Julien Dumoulin-Smith: And what's the timeframe, just to be very clear? When is this going to actually reach in service as far as, like 2017, 2018, 2019? What's the cadence of development that you're seeing out there right now? Can you speak to that a bit?

James Tynion: Yes, the projects that are going to start construction by the end of this year in order to qualify for the PTCs, the wind developers can sort of take their time as long as they're diligent. There's no heavy rush to finish in the normal time for a wind project for construction and completion is between nine and twelve months. So one would think that a lot of the fourth quarter start construction projects for wind could be finished by the third or fourth quarter of 2017. However, if I will bet that whether it's half or one third of the start construction projects that start by the fourth quarter of 2016 may actually not reach in service until the beginning of 2018. Meaning that the turbine supply can be more rational and spread out for their deliveries because there is not this rush under the PTC to get it finished within one or two years. So I think it's just a pricing issue with turbine supply that may push it out. There'll be a big, I think, next third quarter 2017, we'll see a major increase in the in service of wind projects.

Julien Dumoulin-Smith: What are you seeing out there in terms of activity of PPAs before we hit more on the repowering stuff just overall?

James Tynion: The RFP activity from the regulated utilities, I think, is probably pretty much the same, which is at a fairly low level from the point of view of the wind developers such that they would like to see more utilities out, putting out RFPs for the 15, 20, 25 year PPAs. There are not a lot of them but there are some steady increases with offtake. <u>The projects that the utilities that are offering, the longer term projects, are really expecting a high volume of responses and low PPA prices</u>. There still is a lot of pressure on the project developers which then put pressure on the turbine suppliers and the contractors to lower the price of the LCOE. There's still a lot of price pressure, downward pressure.

So we're seeing PPA prices in certain areas that are less than 2.5 cents a kWh. You know, the rule of thumb is if you're 2.9 or under 3 cents kWh for your price, it's hard to make those pencil out for financing, but project developers are able to do so. A low interest rate environment for debt helps that and it's countered by the higher prices of tax equity financing. So that's on the regulated utility side. So it's, I would say lukewarm. We wish there were more.

But the good news is that there is an amazing increase in the corporate PPAs. Corporates, major corporates are becoming quite active as off-takers either for buying wind energy for a particular installation at that corporate or more of a broader financial PPA that may support renewable supply from a broader area, not supplying one particular installation. So, for instance, of the Fortune 500, this is from a panel yesterday in New Orleans, or Wednesday afternoon I guess, of corporate off-takers that of the 500, I should quote, I should credit Dan Gross who is a blogger on Slate who moderated a very fine panel down there. **And he said that of the Fortune 500 companies, there are 260 companies that have sustainability goals and we think there are about 120 of the Fortune 500 that are looking at renewable energy as off-takers.** Twenty of those companies have already signed up multiple PPAs. And we're seeing that very much expand. Folks have ready <u>heard</u> about Facebook and Google and Walmart but other people like GM and other major industrials. So we see a higher demand on the corporate side and that's a new product. And it's working through the kinks.

But we're seeing optimism there, Julien, in the market. And regulated utilities should be looking at this carefully both as an opportunity and as a challenge. Because what we would expect is that the regulated utilities who have many of these industrial customers in their service territory, I would guess that they should be talking to those major customers. Especially the ones who have made public statements that they're in support of renewable energy and try to partner with them to work out arrangement where the company can sponsor in one way or another a product or project. And yet not sort of pull that customer off the regulated utilities, off their rate base. But that is a

risk I can see over the next five years that some of these projects may leave the regulated utilities customer base. So the smart (unintelligible) working with them.

Julien Dumoulin-Smith: Jim, if I could jump in, what is the size of the repowering opportunity here? So just let's dive a little deeper here. What do you see the marketplace as being? You mentioned three specific locations in California. How big is the marketplace in California? In Texas and other regions of the country? How would you frame it regionally? How would you frame it in terms of the aggregate opportunity?

James Tynion: Okay, well I don't have exact figures here and that may be worth a follow-up Julien, a note to your clients here, but I think what we need to do is ask how many wind farms that are existing today were in service for more than ten years? **And my gut sort of tells me that in the short run let's say there may be 5000 MW.** It's hard to say, though, Julien because the old projects may be a 30 MW project out in a field and that project could be repowered at 100 MW on the same footprint just because of bigger turbines and a more efficient layout. So it's hard to make a correlation but I would say it's in thousands of megawatts are likely to be powered over the next two to four years. We know in the Altamont I think three big projects have already been repowered. And I think there are two that are, these are I think in the hundred megawatt range, are planning to do a repowering financing in the next six months that will come in in probably 2017.

Texas, probably less so because those projects really only started to be installed 2005, 2008 so they're just starting to get into their ten year range and the cost benefit analysis of an upgrade may be less. One of the big issues for repowering would be the relationship with the current PPA. So if you've got a 20-year PPA and the project is 15 years old, then you have to work with the utility to figure out whether taking the whole project down for six months or you're probably going to go into default under the PPA for your delivery requirement. So it would require some kind of renegotiation. I'll bet that most of the utilities would like to do that because then they can renegotiate term and price. And so the parties need to come to a good agreement on the cost and benefit revenue there. But that will take some negotiation. I think there's less incentive to do that if you're in the first third of a 20 year PPA, you might as well wait a while. In Texas, if you have more of these projects that are merchant, quasi merchant or have a shorter hedge, those are different economics, you know, push and pull.

And I guess the other areas would those with original old turbines such as in northern Iowa, southern Minnesota; which were after California the next front line for wind development 20 years ago, in the mid-90s. So Xcel for instance, as a utility, is likely to have more in their service territory in Minnesota and possibly Colorado than some other utilities right now other than California.

Julien Dumoulin-Smith: So Iowa and Minnesota are what we should watch?

Janes Tynion: Right.

Julien Dumoulin-Smith: Are there other known repowerings that are undergoing right now?

James Tynion: I've not heard of any on the eastern seaboard. It would really be focused on the older turbines, older projects which as I said, it's California and the upper Midwest that may have really gotten started a long, long time ago. And one of the things that is attractive now at these places for repowering is that as these projects have been up and operating in an area for 15 or 20 years, the local communities have gotten used to the wind and if there were any issues with either noise or any kind of inconvenience to the neighbors, any visual issues, they're basically all baked in. So the environmental **permitting risk on a repowering is probably far less than a new project**. So that's an attractive advantage. The new projects would still have to, you know, undergo new environmental reviews but presumably they're already with compliance with most of the new rules.

In California, particularly northern California is the area that's been very sensitive for eagles and other birds. And because of the Altamont Pass is a flight pattern for a lot of migratory birds and the golden areas and the older turbines out there that were built on lattice towers, and the rotor speed of the older turbines was much more rapid than the newer turbines that are taller. The sweep of the new turbines is different and it's a

little safer for the birds. They're able to see it. So and with new mitigation measures that are underway with the California Fish and Wildlife, we think that those projects should be able to get new permits and new financing pretty easily.

Julien Dumoulin-Smith: So in terms of other practicalities, what are the capacity factors on some of the stuff you're seeing out in California? And what is the contemplated increase. I mean, I'm just kind of getting a sense like how much of a spread in improvement and efficiency do you need to see out there to make these things worthwhile? [Sentence deleted.]

James Tynion: Well I think again, this is not a scientific answer but if you're picturing you're postcard of Palm Springs with 2000 turbines out in a field in some Mercedes ad at the Super Bowl, all of those turbines are at the most maybe 30 meters high, you know, 100 feet high turbines, towers. And they're very tightly packed together. The current standard size of the towers are triple that. I mean 70, 80, sometimes 100 meter towers before you then reach up with the blades another 30 meters let's say. So at the same location the wind, if you're another 200 feet higher in any particular location, the wind speed is going to increase, I don't want to say geometrically but dramatically. And the efficiencies of the turbines in the same location just capturing the wind 200 feet higher are much more. So, for instance, a **capacity factor of 32% could increase to 45% and each percentage** increase is a dramatic increase in the amount of kilowatt hours produced and that's revenue. And the production tax credit. So I would just say dramatic but I don't have exact numbers.

Julien Dumoulin-Smith: And what about the PPA, right? So there's PPA in place on some of these. I suppose a lot of the California stuff and the Texas stuff would be and even the legacy stuff in Iowa, those would be running off of PPAs for the most part. So there wouldn't actually be a PPA in place. But to the extent to which even there was, as you've talked to folks, I mean would you imagine that this would be a renegotiation of the existing PPA or would they basically be an EG, like a (blend) and extend to the customer? Or is this like a, we're going to rebuild the towers and just keep some of the incremental megawatts that we're able to capture here?

James Tynion: Yes, I think the three options you described, each of those three options, would be part of a conversation with the local utility. It really depends, because of the increased renewable portfolio standard, in California in particular, they're going to be looking for new supply. And they're going to be looking for that supply at, you know, a reasonable cost to their rate payers. So the developer has to bring a value proposition to the utilities to get everybody to cooperate. To do it in some kind of hostile manner or to do it in a way that has the least discussion with the local utility probably is possible.

So with the idea that some of these **old PPAs and some of them are 30 years old**, they were standard contracts, SO2, SO4 contracts that were put in place in the late 80s, those contracts **may not have detailed provisions on a minimum amount of power that needs to be produced**. And so if half of the windfarm is out of service for several months, they may not go into the default because there's no minimum to produce under certain PPAs. Therefore, the developer could probably do this and just inform the utility that their 50 MW project is now going to have a nameplate capacity of 100 MW although the local PPA, they're only going to be required to deliver the first 50 MW under the old PPA. And then the developer can try to get a second PPA for the second 50 MW. I can imagine if that's the opening (salvo) from a developer, that the local utilities would object to that. And there have been some cases and even litigation that the traditional, the delivery under a 50 MW PPA with a 30% capacity factor is, you know, do the math, is some expected volume of electricity. And then if you double that, the utility will say you're in violation of the PPA. And there's been litigation on that over the last 20 years and usually the parties will settle out for a renegotiation. So your idea of an extent and blend is really probably where we're going to be going because that will probably give the best long term stability for the developer which would then permit the best option, the largest number of options for financing.

Julien Dumoulin-Smith: So at this point I think we'll take some questions form the lines.

[Sentences deleted]

James Tynion: Julien, before we get a question, I've got one other comment I wanted to mention on repowering. [Sentence deleted]. So, one of the reasons we think that the repowering guidance was included in this guidance, was that it was the result of some questions that came from a few major developers in the business. And those developers are planning on repowering and the question came up internally. So assuming you have a 15-year-old project and you're plan is to tear it all down but maybe use every third foundation. Or, of those, every third foundation you may keep the base of a tower. And what you're going to do is in essence, reinforce that foundation and add some, you know, use a portion of the tower and build on top of that for your new bigger, taller tower for the bigger, taller turbine. So the question that needed to be answered was, if I add my 80% of new value to the project today 2016, will I be disqualified if my 10 or 20% is 20 years old? They wanted to make sure that the in service of the small, old piece would not disqualify the 80% of the new piece. And so I think this is very helpful in clarifying no, you're installation of the new 80% is the thing we're going to be focusing on for qualification for the PTC. So I think that eliminates a cloud over repowering plants and that's why it was in this notice.

So we think that should be helpful for developers and financiers to figure that out. And also, that should also clarify what's the value of the used equipment. The concept of the 80/20, meaning that if you refurbish an asset, at least 80% with new equipment, then it will qualify as a new asset. That concept has been in the tax law since 1968, when we were back in the railroad and aircraft leasing days, when equipment used to get refurbished every few years. So since 1968, this has been part of the **IRS rule that 80% of updated equipment would transform the asset into a new asset for the tax benefits**.

Julien Dumoulin-Smith: Thank you. What was the prior guidance, if any, that existed for the wind industry?

James Tynion: There wasn't anything. I mean, there have been over the last couple of years some guidance on updates and retrofits and repowering for things such as biomass facilities and other similar facilities but they're all following the 80/20 rule. So that 80/20 rule has not changed. The only thing that this guidance from two weeks ago clarified was the timing of the new investment and how it would count going forward.

Julien Dumoulin-Smith: What was the update on May, I suppose it was 18th or what have you, vis-à-vis the guidance that was released initially?

James Tynion: It was really just to fix a couple of typos actually and nothing dramatic from our look. So as **between the May 5th and the 18th guidance, I don't think that's a material change.** I think they just clarified that's the effective date and they clarified a math error.

[Sentences deleted.]

Operator: Our first question comes from Client 1. Please go ahead.

Client 1: Yes, thank you for the call. I just wanted to go back to something you said about being eligible to qualify for being in construction, that there are certain activities that have to be commenced. You can't for example, just move dirt around and say yes, I'm getting underway. So could you just elaborate on that a little bit more in terms of what a developer would actually need to do? Is it, you know, commit X percent of capital?

James Tynion: Right.

Client 1: Or is there actual physical activity?

James Tynion: Sure.

Client 1: And then, dovetailing into that, if you have to have that eligibility qualification met by December 31, 2016, do you have really until December of 2020 to be commercial?

James Tynion: So the very, about the last question; you do have the four years to be commercial. It's amazing. It's good. And but what happened I think it was two years ago or maybe it was 2013, the IRS came out after the Tax Act of 2012 to describe what it would take to start construction by a certain date. It used to be, since 1992, the

deadlines were always placed in service dates. And so three years ago, I think the Congress changed that to be a start of construction deadline rather than a placed in service deadline. So immediately the lawyers all came up with, well, what does it mean to start construction? And within six months, the IRS came out with guidance that described a two-pronged test. And the two-pronged test was either **that you start construction A, by either actual physical activity, it didn't say on the site, but actual physical activity of a significant nature**. [Sentence deleted.] **Or B, you can start construction by spending 5% of your expected total cost by the deadline**. Then that would be deemed to be significant. That was a safe harbor. If you spent enough money, then you didn't need to prove what you did on the site to actually get a tractor around the facility.

So that's where it started, with those two. And then if you started with a tractor on the site, could you just put a guy out there for two weeks and then send him home for a year? No. You had to put him out on the site and you had to **demonstrate continuous construction** until you were finished. Well, what does continuous mean? What happens if it's raining? What happens if there's a lawsuit? What happens if I have a delay on a permit? So over these past two years, IRS has come out with several other clarifications. And most recently, and in each case the clarifications have benefitted the industry. The concept is to avoid fraud here. If it's a real project and you've really started and you are working towards completion, the IRS is not going to hold it against you if you're delayed by financing. There was a concept in a previous guidance that if there's a delay in financing up to six months, the IRS would not count that against you. In the new guidance, that six months is gone, so basically any reasonable, any delay of the financing won't be counted against you. So you have to start and have continuous construction and then that they came out with the two year safe harbor. If you're finished in two years, the IRS is not going to investigate what you did every single month. Now the rule is they're a physical work of a significant nature, what people have to do today is simply demonstrate that they've done something. And that either is, it could be as simple as digging one foundation or out of field of 10 or 50 turbines, or placing an order for significant pieces of equipment had to be the 5%. So it's a low bar, but it's got to be very clear and it does not include things like a great entry road getting to the site. **It does not include any offsite permitting and studies.** It's got to be something that you're committing cash to start construction. I don't know.

Client 1: Great. Thank you so much. Yep.

James Tynion: Thank you.

Operator: Thanks. Your next question comes from the line of Client 2. Please go ahead.

Client 2: Yes, I was curious, do you have a sense for what it will take to prove out the 20% value and the 80/20 rule for kind of documenting that?

James Tynion: I do not. And I think that that's going to be a challenge. I am aware that there are folks right now possibly talking to the IRS to see if we'll get further guidance on that? The common sense just from, again this is two weeks old. So talking to some folks. It would be an appraisal, a third-party appraisal of the fair market value of the equipment that you're still going to use. So the, and I don't know if you were to take 20-year old foundation concrete and some tower sections that cost $100 and were depreciated. You get a new, a new appraisal on what costs are being displaced on a new project, for instance or is it simply an accounting function. I think that's an open question.

Client 2: Okay, I appreciate it.

Operator: Thanks, our next question …

Julien Dumoulin-Smith: Can I just follow-up? I was just going to follow-up real quickly on that last one. Can you give us a sense as to what the 20% would include just, perhaps to give a small statement here? I mean would the 20% of fair market value, include the fair market value of say a, the transmission on the site or the roads?

James Tynion: I mean whatever you think you can reuse. So I would think that the underground cabling, if it was put in and it was of a high value meaning it was a high quality 10, 15 years ago, I would expect that they'd be able to use a lot of that in a

new repowered project. I think many components within the substation could also be used. The definition of what a facility is for this purpose would be, again, usually for PTC qualification purposes, it's turbine by turbine and the timing for when things start, you can use the entire project to sort of qualify all 50 turbines by start of construction for a component of the entire facility which includes a substation and the transmission lines.

So the definition for one PTC facility is one turbine but it's the cabling that goes to the substation so you could argue the entire substation before the power is interconnected to the grid because you need the full substation to get that first spark from that one turbine into the grid. So that's where I think a lot of the values will be substation components, underground cabling. I think the foundation and lower parts of the tower would be a much smaller component of the used equipment.

Julien Dumoulin-Smith: Would you get on building repowering assets? I still think, you said, differently? If it's the 80/20 rule, is it a 10% savings versus what a green fill project would cost that you would be able to repower this thing at? I'm just throwing out a number. So I mean historically.

James Tynion: Yes, I think it's a project by project basis. I spoke to one developer that's thinking of a repowering and they will redo everything. So they probably won't save anything or be very de minimis.

Julien Dumoulin-Smith: I think that the reason we do everything is just because it's because they need more capacity on the lines so they need to redo the underground wiring. They need more capacity to be handled on the transmission that works. So the expansion on that, etc.

James Tynion: Yes, that the breakers and you have more efficient and more powerful transformers, breakers. The utilities, the local grids probably have, there are new requirements for the interconnection, the software updating and then communication. So it's all new.

Julien Dumoulin-Smith: So just to be clear, the repowering really is a PTC benefit and a capacity factor benefit. There's not really a CAPEX discount on repowering the site or at least not anecdotally.

James Tynion: Yes, I think adding to what you said, I would add the permitting. It's the uncertainty of permitting a new site and the time cost in some areas and California's a very strict jurisdiction on permitting. You know, working with an existing site is, takes less time and less money.

[Sentence deleted.]

Operator: The next question comes from the line of Client 3. Please go ahead.

Client 3: Hi. Thanks. I just had a question about the ten years on the repowering. I was asking a hypothetical. Can you qualify in 2016 and then have your ten years basically run in 2019? So you qualify for the 100% PTC but the ten years of the project you're looking at would mature in 2019?

James Tynion: Yes. I think **the PTC runs ten years from your in service date**. The qualification, so there're two. So the qualification would be this year – your qualifying for 100% and it's a ten year PTC from in service. And I will triple check that.

Client 3: Just to qualify …

James Tynion: Beginning on the date, yes, it's from the place in service date.

Client 3: Okay.

James Tynion: So if you start this December and it goes in service 2018, 2019, you've got a ten year PTC at the 100% rate.

Client 3: Oh yes, that's right. My question is I thought for a project to be repowered it had to be in existence for ten years. Is that an accurate assumption?

James Tynion: Oh no. I mean that was just an example of in theory if you think it pencils out after five years, fine. What I'm just aware that it would be these older projects where the cost benefit of redoing a PPA or you may have on projects that are five to ten years old, you likely have either existing tax equity PTC financing that would

be hard to unwind or even senior debts still on the project. Usually after year 12 or 15, the third party debt and tax equity are gone and so you're in an easier position. You have more flexibility with what you're going to do with the project. The original sponsor now has the project free and clear of debt.

Client 3: Great. Thanks.

Julien Dumoulin-Smith: Next question.

Operator: Our next question comes from the line of Client 4. Please go ahead.

Client 4: Yes, hello.

James Tynion: Yes.

Client 4: Okay. I didn't know everyone was lining up for their question. Yes, this is a question in regard to repowering for using the instead of the continuous construction but using the purchasing of equipment for the 5% rule. Does the extension still apply using that?

James Tynion: Yes. So the 5% safe harbor has not changed. That is one of the options that developers have to qualify for the start of construction.

Client 4: Okay. Thank you.

Operator: Thanks. Your next question comes from the line of Client 5. Please go ahead.

Client 5: Hi, thank you for the call today. My question is going back to the equipment purchase, for companies that have multiple projects in a portfolio, are there any restrictions about safe harbor, buying a set of equipment most typically turbine and then allocating it to different projects? Put another way, do they have to designate which specific site they will allocate that equipment to or can you just more generally safe harbor a batch of equipment that could be used at various sites?

James Tynion: Yes, I think this was not changed or dealt with. That issue was the subject of at least one or two guidance. Two or three – let's call it two years ago. And there are some really strict rules about what developers were doing. They were entering into framework agreements with an equipment supplier. Please, I will buy 500 turbines from you and I will safe harbor, you know, 10% of those now, so 50 turbines. And I will allocate those to a project to be determined later.

There are some strict rules about the project itself. The project has to be identified because it's the project that gets qualified, to be placed in services. Qualifications to be eligible for the PTC. And so usually a developer that has ten projects in development, they would have to sort of identify which turbines go to which projects at the beginning. And then there is some flexibility sort of changing your mind a little bit later because project A had a problem with its permits so I'm going to move those turbines to project B. Again, the rule is to avoid fraud here and so I don't think it's possible to enter into a contract to buy 500 turbines when you have no projects identified. That would be a bad fact I would think on any kind of audit. So again, Julien, we could drill down on this question, if you're readers want to, but there are very specific rules about how to move the turbines around and sell them and the timing of when that transaction happens. And who the actual taxpayer is.

Julien Dumoulin-Smith: Do you want to elaborate in the last couple of minutes here and just on what those rules might be just briefly?

James Tynion: Well I think, I don't have them memorized. I'd have to research them. But we've had this question before. The turbines we'll assume with wind. We'll assume we're doing the wind turbines. The qualification usually is: I will spend money to actually buy components of equipment that by the deadline and those components need to be delivered to me into my possession. And it's within, I think it's 3.5 months or 4 months of when you place the order on a contract that <u>it</u> is a binding contract that you're not going to get that money refunded, if you change your mind later. So to (the) direct question, if you have ten projects in development, you can acquire them and then move the turbines around. We've had situations where a first developer had the turbines because they had a developer project identified. That project goes away. A second developer comes to them and says hey, I've got this project that I can use your

prequalified turbines for. And there are certain situations where that's possible but it's a complex analysis.

Again, what the IRS is trying to avoid and this happened with the 1603 Grant Program and especially in the solar field. And there was some possible abuse of these rules with people warehousing modules for grant purposes when they really didn't have projects identified. So there's some sensitivity on this issue.

Julien Dumoulin-Smith: Well I think we're at the top of the hour here so I want to respect everyone's time. So thank you very much for taking the time. Good afternoon. So thank you once more Jim.

James Tynion: You're very welcome.

Julien Dumoulin-Smith: Again, Jim, is over at Morgan Lewis in New York.

James Tynion: Thank you everybody. Bye.

[Sentence deleted.]

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.

NEE: Valuation is based on a SOTP Methodology.
NEP: Valuation is based on 50/50 weight between 2018E DPS yield and DCF on the current operating portfolio.
XEL: PT derived via P/E SOP.
GE: Our price target is based on ~19x our 2017EPS estimate.

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Buy	FSR is > 6% above the MRA.	49%	32%
Neutral	FSR is between -6% and 6% of the MRA.	38%	26%
Sell	FSR is > 6% below the MRA.	14%	19%
Short-Term Rating	**Definition**	**Coverage[3]**	**IB Services[4]**
Buy	Stock price expected to rise within three months from the time the rating was assigned because of a specific catalyst or event.	<1%	<1%
Sell	Stock price expected to fall within three months from the time the rating was assigned because of a specific catalyst or event.	<1%	<1%

Source: UBS. Rating allocations are as of 31 March 2016.
1:Percentage of companies under coverage globally within the 12-month rating category.
2:Percentage of companies within the 12-month rating category for which investment banking (IB) services were provided within the past 12 months.
3:Percentage of companies under coverage globally within the Short-Term rating category.
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Company Disclosures

Company Name	Reuters	12-month rating	Short-term rating	Price	Price date
General Electric Co[4, 6b, 6c, 7, 16, 18, 22]	GE.N	Buy	N/A	US$30.04	10 Jun 2016
NextEra Energy[2, 4, 5, 6a, 6c, 7, 16]	NEE.N	Buy	N/A	US$123.83	10 Jun 2016
NextEra Energy Partners LP[2, 4, 6a, 16]	NEP.N	Neutral	N/A	US$28.80	10 Jun 2016
Xcel Energy Inc.[7, 16]	XEL.N	Sell	N/A	US$42.75	10 Jun 2016

Source: UBS. All prices as of local market close.
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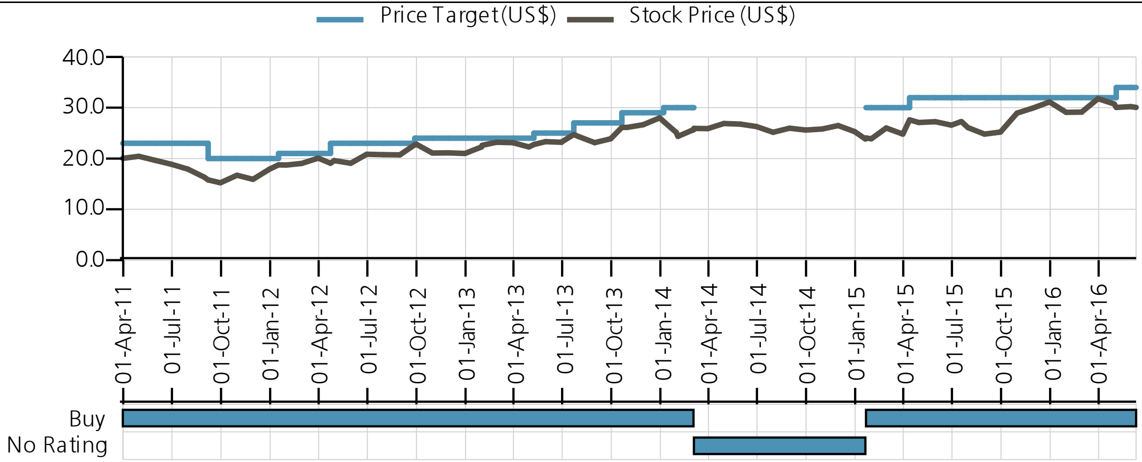
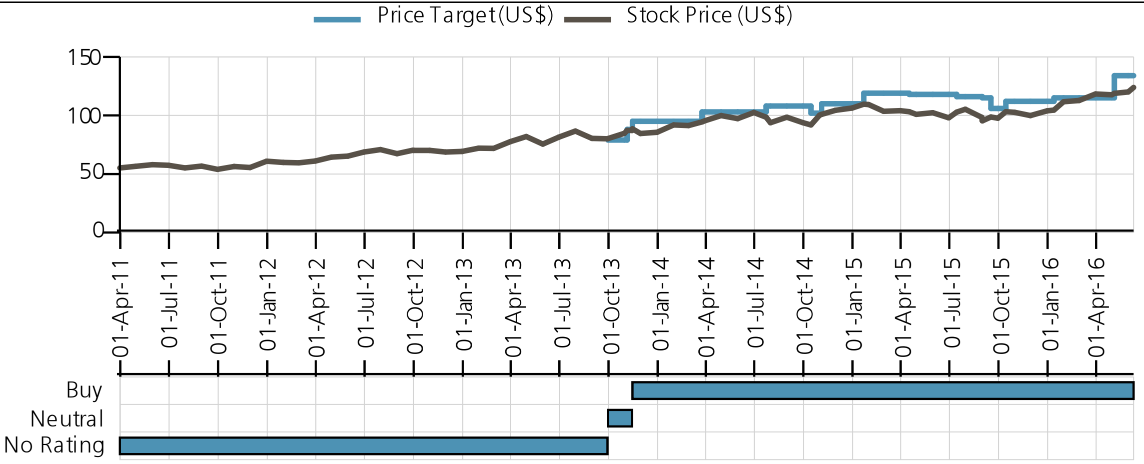
General Electric Co (US$)



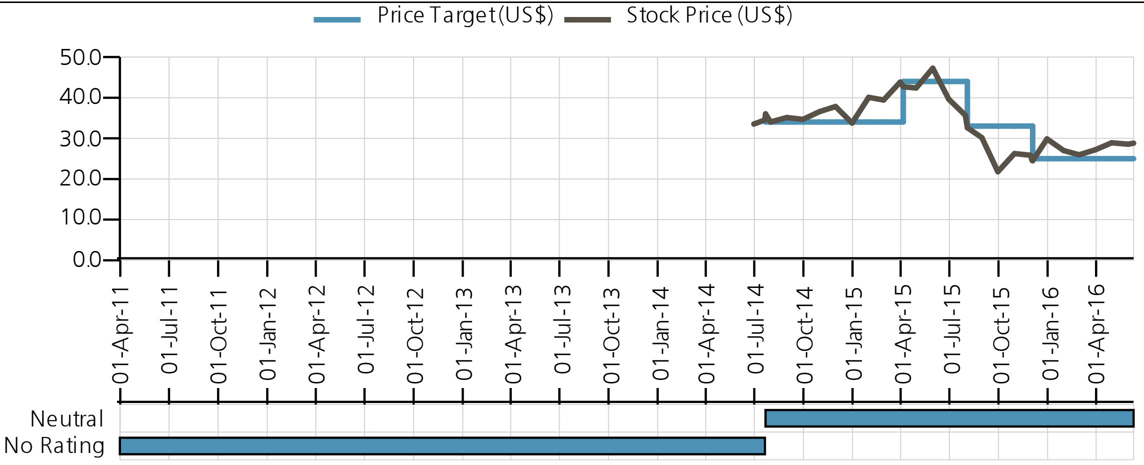
Source: UBS; as of 10 Jun 2016

NextEra Energy (US$)



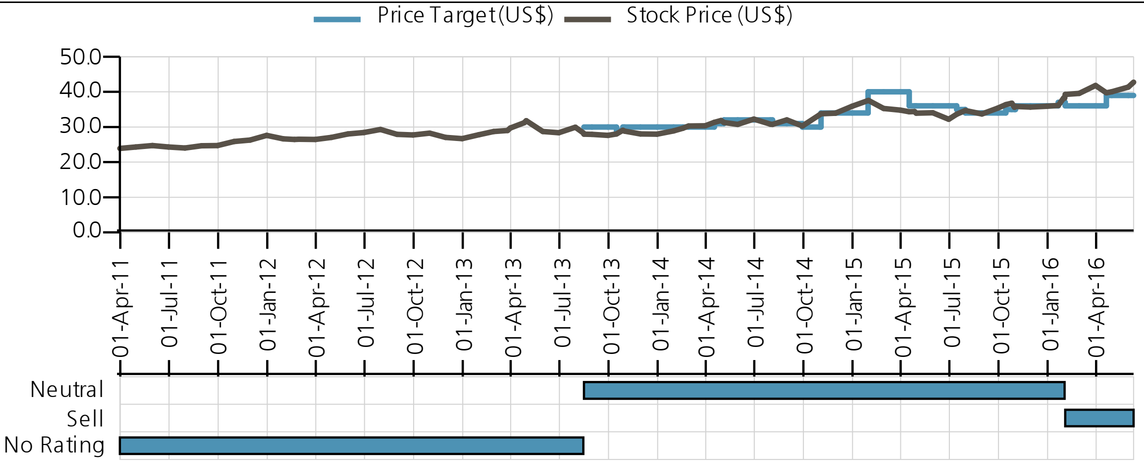
Source: UBS; as of 10 Jun 2016

NextEra Energy Partners LP (US$)



Source: UBS; as of 10 Jun 2016

Xcel Energy Inc. (US$)



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