US Electric Utilities & IPPs
DC Transmission: The 'Wind by Wire' Prospects
(Includes Conf Call Transcript)

A more genuine ‘non incumbent’ threat vs. other recent merchant partnerships
We held our latest conf call with Michael Skelly, President of Clean Line Energy Partners, which is in the process of developing several High Voltage Direct Current (HVDC) transmission lines across the country. We see the business poised in a niche which addresses several key issues for utility sector investors – not the least competitive bid transmission across the RTOs (although Clean Line’s efforts are specific to wind and DC). Competitive transmission via FERC 1000 mandates have primarily been incumbents and non-incumbents partnering through JV efforts rather than the utilities entirely losing the investment opportunities to outsiders. We see Clean Line’s model as a more aggressive standalone competition to the incumbent utilities, should their attempts of blazing out a fresh trail succeed (albeit their efforts are linked to Wind specifically).

The ‘wind by wire’ trade: how does transmission figure into the metrics?
Central to Clean Line’s efforts are efforts to export low-cost wind from the Central Plains/Upper Midwest states to other regions in the country. Mr. Skelly remains adamant that the principle issue in pursuing his efforts relate to citing and permitting of his projects, of which a litany of challenges exist (and have been highlighted of late); in contrast, the economics he suggests are quite clear. With wind selling net of PTC at ~$15-30/MWh and the all-in cost of their lines at ~$20/MWh, this provides an all-in delivered prices as low as ~$45/MWh (and ~$60/MWh ex-PTC). The key question is to what degree the ‘wind by wire’ trade can compete with more locally sourced renewables in the Southeast and Mid-Atlantic to meet RPS targets (it would appear yes, with the caveat around the time of use benefits of solar despite its higher price at ~$50-60/MWh). Additionally, given the need for long-term offtake arrangements remains the willingness for energy marketers and states to procure renewable needs via long-term PPAs rather than via short-term procurement of Renewable Energy Credits (RECs). While PJM would appear an ideal end-point for the Clean Line, given the ability to deliver into Illinois – and deliver RECs to qualify for east-coast REC markets, none of these markets offers long-term contracts (yet?). A further benefit for the ‘wind by wire’ trade would relate to potential for an extension of just the PTC for a further two years, without solar getting a similar extension for the ITC.

What is the cost of equity on DC merchant lines? More risk, more reward.
In discussing return thresholds, Mr. Skelly suggested required returns were easily into the teens to take on the corresponding merchant development risk on DC lines given the significant permitting and development challenges. We see this as a relevant factor in both evaluating the risk profile and establishing expectations for peer DC project developments, including ES with Northern Pass and particularly for ITC with its proposed Lake Erie line and even Puerto Rico efforts. We think returns for ITC if successful may prove outsized relative to traditional ratebase investments (albeit investors should discount the risks of success at the outset accordingly as well).

What about the wind outlook? Transmission would just add robust outlook
While anecdotal datapoints of build in 2015 and 2016 remain exceptionally constructive, supporting NEE’s recent positive revision to both near and long-term EPS forecast with 2Q, we see transmission as only adding to the opportunity if even successful in overcoming hurdles. Bottom line, this remains a wildcard to meaningful Midwest renewable upside – the primary market of late for NEE’s development efforts.
More clearly defining the offtaker end-market
Clean Line expects demand in the West and Southeast driven by PPAs with large, integrated utilities. In PJM, rather than mostly demand from long term contracts, it will be from a combination of hedge providers, integrated utilities, and industrials/corporations (~1000MW of transactions with likes of Amazon and Google and Facebook etc. recently) Specifically, mgmt. expects PJM to be more of a push-oriented model, with producers buying capacity on the lines and pushing into load markets; but for other projects involving delivery into regulated markets, the model likely will be more pull-driven. Anecdotally, on two projects (in the Grain Belt, and also Plains and Eastern Project) where Clean Line has had open solicitations, they got ~4x the MWs of interest. Overall, we would expect interest in the lines to pick up as boxes are checked in the permitting process, and clarity emerges in terms of likelihood of completion.

State/federal regulatory approvals and permits for routing remain key risks
To get a project to start of construction requires several reviews/approval around the routing (e.g. lines in the Eastern Interconnect is a 200 feet wide, 750 miles long line); this means projects are exposed to several layers of regulatory risks in each jurisdiction the line passes through. Even though Clean Line has an interstate/national focus, we think for pure play competitive transmission projects to take off, their success in these efforts will be key. From the utilities perspective, what will be key will be owning the existing right-of-ways for existing lines (as well as more fully understanding regional flows) – which may create a bias towards incumbents to retain the vast majority of the ownership structure and develop a disproportionate amount of the regional utility assets. The key challenge in developing DC lines appears to be in states that are crossed, without meaningful delivery points of power.

Cost for delivered wind over HDVC cost effective even without PTC?
HDVC is ideally suited for the purpose of integrating far flung windy areas to load centres because power loss over large distances is much lower than that for an AC line but this comes at an additional expense of "several hundred million" dollars for convertor stations to convert AC coming out from the wind farms into DC, and then the DC back into AC to make it usable – meaning DC lines are not necessarily cost effective over short distances. According to Clean Line, a DC line also has a smaller right of way footprint than an AC line which also adds to cost efficiencies. For a 750 mile long line the AC-DC conversion stations are ~1/3 of the capital costs, with the remainder is the line itself plus right-of-way and permitting costs etc.

Clean Line estimates that for each of its projects constructed, ~4GW of new wind projects which could not get built due to the lack of transmission (the lines themselves can carry ~3.5GW)

We show below costs vs rival technologies.
Higher returns on development capital commensurate with higher risks

Given the regulatory/permitting risks involved in early phases, the cost of capital for development money is relatively high; but once a project is built or even about to go into construction the cost of capital comes down dramatically. In terms of returns, for development capital, Clean Line estimates investors want to see the possibility of a multiple of the capital invested at that risk; and that many of them would look to monetize the value of their investment 6-7 years into the development cycle once the project has been de-risked. Targeted capital structure through construction would appear to be 50% levered, with long-term debt capitalization targeted in the ~75% range (in contrast to authorized equity returns for ratebase structures).

Timeline: earliest Clean Line project online early to mid-2020

In terms of timeframes, the earliest project would be the Plains Eastern Project connecting the panhandle of Oklahoma to the Southeast. Clean Energy expects a decision from the Department of Energy by the end of this year. Construction is expected to start in 2017; construction will be around three years bringing the project online early to mid-2020.
Where are Clean Lines projects?

We show below Clean Line’s map of projects connecting high wind-resource areas to load centres. Primary focus is east/west projects delivering into the Eastern markets, be it the Northeast, the Mid-Atlantic or the Southeast from Midwest projects.

Figure 2: Clean Line Energy Partners: projects vs. existing transmission

Source: Clean Line Energy’s presentation slides used on UBS conference call
Highlighting the need for interregional transmission

The map below shows the major regional transmission projects; and wind development.

Figure 3: Regional transmission capacity and wind development projects

Source: Clean Line Energy’s presentation slides used on UBS conference call
Conference Call with Clean Line Energy

We held our latest conference call with Michael Skelly, President of Clean Line Energy Partners, which is in the process of developing several large-scale DC transmission lines across the country. We present below the transcript of the call which has been edited for grammar and ease of reading.

Please let us know if you would like to receive a copy of the slides that were used on the call.

To listen to a replay of the call, use the dial in details below:

Replay Info:
Toll-Free: 800 633 8284
Toll: +1 402 977 9140
Passcode: 21774751

Julien Dumoulin Smith: Good afternoon everyone. I appreciate you taking the time. This afternoon we’re joined with by Michael Skelly, Founder, CEO, of Clean Line Energy. Clean Line has built out long distance DC transmission. He’s a long-time wind veteran; involved in numerous companies including Horizon.

And really what they are trying to get off the ground is basically wind by wire, if you will. And so I thought it was relevant to have the conversation today; both around their efforts for DC transmission in the country, and also specifically to address the renewables by wire thesis as it begins to manifest itself across a number of different regions.

And with that I will turn it over to Michael to go over a little bit of background on the subject of DC transmission, its place in renewable procurement and where they fit in the mix. So good afternoon Michael, how are you?

Michael Skelly: Great, thank you very much Julien and thanks for the opportunity to chat this afternoon. We’ll start with the supply side. Julien as you mentioned I’ve spent a lot of time in renewable energy development at Horizon Wind. And many of us here at Clean Line or at least the management team were involved in developing Horizon – and from that gained a good understanding of the
All of our projects originate in the really windy central parts of the country. And over the last decade and a half a lot of projects have gotten built in this area but the limit to growth that has come about it's not land or permit, it's available transmission. And transmission is, we believe, the key ingredient to getting more renewable energy on line.

And we started Clean Line in order to address that challenge. And we believe that the reason that an independent is best suited for this job is that most of our utilities have a state-based regulatory mandate; they're charged with serving a local load. They are not thinking about how to solve the multi-state challenge of citing interstate transmission.

So it’s actually necessary that an independent go take that on. In addition to the fact that local utilities typically don’t have access to the development capital that go into permitting and citing and developing a project like the ones that we’re putting together.

So to begin on the supply side, as many of you know, because of advances in technology - either bigger blades, taller towers, better control algorithms, stronger, more lightweight materials - you can now produce wind energy in the central part of the country for about two cents a kilowatt hour. And that’s inclusive of the currently available (or in-transition shall we say) production tax credit. Without the tax credit we believe that wind would be somewhere in the 3-1/2 to 4 cent range in this part of the country.

And in all these parts of the country it’s fairly straightforward to build projects, to permit them there are landowners who are interested in leasing their land for wind production. So there's a very deep supply basin if you will for the resources that we want to tap. And, indeed, there are developers active in all these areas with land positions and meteorological programs and permitting efforts underway. And what they need in order to get their projects built is access to market.
And then on the demand side our projects deliver energy - up toward Four Corners, another further west and then in the East (where two of them connect into PJM). And then in the Southeast to the TVA system just outside of Memphis. In addition to those connection points two of our projects have intermediary stops along the way; one was delivery energy to a midpoint converter station in Missouri and the other one to a midpoint converter in Northcentral Arkansas.

In the Southeast if you add up the amount of wind that utilities are buying today, amongst the southern family of companies and TVA and a few others; more than **3000MW of wind are under contract today**. Those contracts are **with producers in Oklahoma and Kansas and places like that**. And they’re **using the existing AC transmission system** to get that power. **Unfortunately that system is strained** and you really can’t do much more in terms of getting wind to market. To say nothing of the long-term variability or risk if you will associated with moving wind across SVP and My Solar and so on to get to the Southeast.

So we believe that our product will be a valuable addition to the grid for the Southeast. And then going on to PJM, PJM has both renewable portfolio standards and if you look at the Clean Power Plan a number of the states in PJM are the states that have to do the most work in terms of meeting the requirements of Clean Power Plan. So we’re interested and working hard to meet the demand in those states. And then out west I think it’s no secret that California is quite keen on increasing from a 33% RPS to a 50% RPS. And as they go to higher and higher levels one needs to move beyond just solar but also around-the-clock resources are very helpful in terms of meeting the demand there.

So how are we going about doing this? The technology that we’re using on our projects is direct current technology. For those of you all not familiar with that, it’s well known that if you want to **move a lot of power a long distance, high-voltage direct current is the right application** for that job.

The **disadvantage of HVDC is that you have to invest several hundred million dollars in converter**
stations on either end or in the middle of the line. And that prevents its use for shorter distances. But over long distances because of the much lower losses associated with HVDC lines it’s the application of choice. So if you look at transmission build outs around the world, what China has done to move hydro and coal from the inland areas to the seaboard, those are almost all HVDC lines.

If you look what Brazil has done in terms of tapping inland hydro resources down to Rio and Sao Paulo those are also HVDC lines. So if the job or the challenge at hand is moving a lot of power along distance, HVDC is the best solution because of smaller right-of-way and much lower cost.

In terms of our business model this technology actually lends itself quite well to the business model that Clean Line is pursuing. And our model is basically a merchant model and effectively we would contract with producers who want to get to market. So large wind energy developers would arrange to sell their power at the end of our line and they would buy capacity from us in order to get to market.

Now that’s very similar to what one sees in the gas pipeline industry where you have a combination of both demand and supply contracting for pipeline capacity in order to connect producers with markets. In transmission however it is typically the case that most transmission lines are built through what’s called a cost allocation process. And what happens in those circumstances is that SPP or PJM or MISO - whoever would get together with the various member utilities and their various State Regulatory Commissions and decide on a transmission expansion plan. And the cost of that plan would be spread out amongst all of the users of the grid in that particular area.

We don’t have an inter-regional cost allocation process in the US - that’s not even available to us. So we depend upon a participant-funded or a merchant model where we would enter into long-term contracts with the producers to get to market; or the people who have demand for the electricity and want to have access to these resources.
The big challenge that we are tackling here and this is no secret is that we don’t have federal transmission citing authority nor do we have federal plans that drive the development of the grid. **So one of the biggest part of our job is to put together the different regulatory approvals and permits that we need in order to build the line.**

So that involves a very detailed routing process with a tremendous amount of stakeholder input. If you look at the lines in the Eastern interconnect here all of those lines have routes and when I say a route what is an actual line that is 200 feet wide by 750 miles long. So each of these lines has a route associated with it that’s either been approved by or is undergoing review by the relevant state of federal regulatory approval.

As I think you mentioned Julien, we’ve been at this for about six years now. And so we are working our way through all of the different processes. And what we do is on all of our projects we either work with directly through the State’s Public Utility Commission or in certain cases we are looking to avail ourselves of Federal Transmission Authority or Transmission Citing Authority where it exists.

And as we know it’s not ubiquitous - federal authority only exists in certain states. We don’t have it all over the country. But in those states where it’s available we think of it as a backstop in the event that for either because of the state’s arcane statute or some other reason we have to go about citing the line in a different way.

So we’re going through all these different processes. Those processes take a number of years for the approvals and that’s obviously on top of the process that one goes through in order to develop an appropriate route.

For each of our projects we will see constructed out in these windy parts of the country - **for each project approximately 4000MW of new wind.** And these are new wind projects that they could not get built due to the lack of transmission. And again each line will carry 3,500MW.
The lines with intermediate converter station will carry 4000MW so those are obviously very substantial investments. And the generation that will go along with the project in order to support them will be investments on the order of $5 to $6 billion each in addition to the substantial investment that we’ll be making on the transmission side.

One of the big challenges of moving a lot of power is how to handle the injection of that much power at the receiving end of our line. For that and to get those approvals we go through either the RTO, in this case PJM, or - and/or the local utility.

So there’s a whole interconnect process that we go through with a lot of studies that go into making sure that any issues on our lines don’t cause issues on the rest of the grid.

And then the other big consideration that we think a lot about is what do the weak-grid interactions with large numbers of wind turbines look like. We spent a lot of time with SVP and My Solar on those sorts of issues in addition to a lot of efforts with the various HVDC equipment manufacturers. Of which there’s just a handful of them globally.

So with those introductory comments I would be happy to take questions. We’re excited about this - transmission development is not for impatient folks or for people without a lot of tenacity to get the job done. Well we’ve got a pretty tenacious crew here. We’ve been at it for a while. When we started the company we did sell with an eye to this increasing reliance on renewable energy. And now with the advent of the Clean Power Plan we’re very excited about the role that our projects will play; not only in meeting the needs of the Clean Power Plan, but also providing some very, very cost-effective energy for different parts of the country.

Julien Dumoulin Smith: Great Michael. I really appreciate it. I wanted to step back and just provide a little bit more of a holistic sense. I know you tried to address some of it in part, but what is the cost of your solution? You said wind today is maybe 1-1/2 to 3 cents in these ideal markets that
you’re exporting it from. What’s the cost of your solution to bring it to another market? And then again could you maybe give us sense of what it costs in dollar per mile. What does it mean in terms of the DC upgrade and step-down interconnection points.

Michael Skelly: Yes, okay, great. So, yes, in terms of production costs of wind - we heard of prices as low as a penny and a half. But it’s a penny and a half to 2-1/2 cents to produce wind in these areas. And we will actually sell our capacity on a kilowatt month basis. But when you back all that out it’s going to cost producers about two cents a kilowatt hour in order to get to market. On the shorter lines it’s a little bit less, on the longer lines a little bit more.

So we’re talking about an all-end delivered cost of under 4-1/2 cents. And if you go to Slide 5 obviously the numbers move around a lot. And we won’t get into the “what does gas cost today with a combined cycle turbine” and all that debate. Those are numbers from Lazard’s LCOE analysis. But if you focus on the left side of Page 5, we’re confident we can be well under 4-1/2 cents with the production tax credit and under six cents without the production tax credit.

Julien Dumoulin Smith: And just to be clear about this, the 4-1/2 cents, you’re assuming basically 2-1/2 cents per kilowatt hour for the transmission costs. And what distance are we talking about?

Michael Skelly: So if we go 750 miles it should cost two cents and change.

Julien Dumoulin Smith: Got it. And do you know how much of that is the step up/step down versus the line itself?

Michael Skelly: So if you’re doing three converter stations, 750 mile long line the conversion stations are going to be about 1/3 of the capital costs and then the line itself will be the rest. And then you’ve got to plus right-of-way and permitting costs and so on.
But that in terms of getting from the wind to our converter stations - if you go anywhere within a 20 mile radius of our converter station and build a 1000MW wind farm, the cost for the collection system are baked into the two cent production cost for wind.

Julien Dumoulin Smith: Got it. Let’s just quickly talk here around the cost structure a little bit further. And it’s a tough question - how do you think about cost of capital for this business? It’s a different business model than developing projects on a rate-pay basis. How do you think about that?

Michael Skelly: The way we think about that is it’s almost two businesses. And they’re very, very different. One is a development business where you’re risking tens of millions of dollars to put together the permits and the regulatory authorities around building a line. And that is a risky business. It takes years for things to unfold. There’s no guarantees. You could spend a lot of money on a line and then have it could all come to naught.

And the cost of capital for that development money is reasonably high because it’s a fairly risky business. Once a project is built or even about to go into construction the cost of capital comes down dramatically. But the risk associated with development are binary and there’s multiple failure modes.

But once a project is built or contracted on the revenue side and they’re contracted to get built, then there’s a tremendous amount of very low-cost capital available. Because that’s the piece of the value chain that investors really prefer to focus on because they’re the investors who are typically not so keen on taking regulatory risks. They’re much more comfortable with operational risk or even technology risk (even there is not much of it in this particular case).

The risk that really drives up the cost of capital is all the regulatory processes that we go through.
Julien Dumoulin Smith: Any sense more specifically on the premiums you would think in terms of looking at the returns?

Michael Skelly: In this business you put tens of millions of dollars into a line and there’s a possibility that those tens of millions of dollars turn into a zero. In my experience in the Web business, and really all development experience, development businesses are like this. In those situations developers looking for a multiple of their capital risk and in the case of lines that are under operation there’s not that many - transactions or reference points out there.

But we’ve seen levered returns in the upper single digits in operating assets. So the cost of capital for an operating project is very, very low.

Julien Dumoulin Smith: Right but development is going to get a lot higher, in theory?

Michael Skelly: Yes. For development, again, in our experience investors want to see the possibility of a multiple of the capital that they would have at risk. And then the question is how does one realize the value for that. And its different investors think about it in different ways. But many of them would look to monetizing the value of their investment six or seven years into the development cycle; want the project to have been de-risked.

And others might want to parlay their position in a development asset into the opportunity to deploy capital at a a better rate of return. And in our company, we have private investors Bluescape Resources, and Ziff Brothers Investments, and National Grid as investors. These are all on Page 18 by the way.

And as you can imagine different investors have different motivations.

Julien Dumoulin Smith: Yes, absolutely. So moving on - can you elaborate a little bit on who the potential off-takers are for these kinds of projects? You clearly have a few different projects you’re evaluating, who in your mind are the key targets to getting these projects off the ground?
Michael Skelly: Yes. Okay so in the West where we have a market which is really driven by utility PPAs, those would be large, integrated utilities. In the Southeast a similar dynamic where you have very large, integrated utilities who have bought a lot of renewable energy in the past. We expect they’re going to want to buy more. There’s folks like Southern, there’s TVA and there’s a bunch of smaller players, Entergy, etc., in the Southeast.

And so those we believe are logical parties that take an interest in this thing. And PJM is on Page 12 of the deck. But you have a combination of hedge providers, some integrated utilities, we’ve seen industrials or big corporations that care about where they’re getting their energy.

We’ve seen about 1000MW of transactions with likes of Amazon and Google and Facebook and so on. And that’s a fairly recent development - just in the last few years. But those have become fairly big players in this space. So PJM you’ve got a lot of different choices.

So in PJM we think our business model is more likely to be a push-oriented model. Where the producers would buy capacity on our lines would be pushing their way into market. For the other projects where we’re delivering energy to a more regulated markets we anticipate that that will be - they’ll be more pull-driven.

And that’s also a reflection of the fact that in PJM you can deliver into a liquid market and sell your RECs over here and your power over there. But in more rigid a market that’s not a possibility.

Julien Dumoulin Smith: You talked about push-oriented model. Are you saying effectively you don’t actually have a deep market for long-term off takes? Are people willing to take the merchant rack risk and sign up for these kinds of deals just to be clear?

Michael Skelly: Well so if you look at what’s driven the PJM market in the past, it’s a combination of these three things. It’s the big industrial loads, its integrated utilities and then
it’s developers who will sell power under a hedge and then RECs under shorter-term contracts, etc.

So, yes, that’s happening today. If you just add up the demand in PJM and the current supply in PJM, there’s a big gap between those two; and we believe that we and others are looking at that gap and stand ready to service.

So we’re optimistic about that. And then these things can also evolve. NEPOOL ended up with a situation where that gap got big enough that prices were getting pushed up to alternative compliance payment levels. I don’t think that will happen in PJM. But as markets evolve and then people you pay commission and someone starts things about other options in order to ensure that the renewables are available. So that’s happening now in a number of PJM states, thinking about what’s the right contracting modality in order to ensure the lowest costs for their rate payers.

But today a lot of projects do get built on the strength of existing circumstances in the market.

Julien Dumoulin Smith: I’d just be curious, again to hammer that home. How deep is that market on your side? And to what extent do you take merchant risk yourself? Are you willing to take some of this exposure yourself as a developer?

Michael Skelly: Well I’ll take the first part of that first. So yes we spend a lot of time with the producers who are active in our resource area. And it’s a several-step process. We start with requests for information or to identify a list of developers.

And then we run open solicitations. On the two projects that we’ve run open solicitations to-date typically we get about four times the MW of interest. So for Grain Belt we did an open solicitation. That’s a 4GW line and we got 20GWs of transmission requests.

Now it’s our job to negotiate precedent agreements and so on with them. And basically what those agreements will say when it’s all said and done, and obviously this
happens once the projects are permitted. Then we would agree that we will build the line and they will agree that when the line comes online they will purchase service on the line.

On the Plains and Eastern Project we did a similar open solicitation and for the four GW capacity, we got 17GW of interest. So there’s a lot of things that we worry about Julien but finding enough wind in western Kansas to fill our lines is not - it’s not the thing that we worry about the most.

Julien Dumoulin Smith: So if I were to summarize, it's clearly the development issues and the permitting issues rather than the market issues about finding off takers once you get it to PJM.

Michael Skelly: Yes, Yes we think there’s structural issues that make the PJM market harder than a simple holy grail for renewable energy developers is this 25-year PPA with a utility with a great credit rating and all that. That’s perfect. And you don’t have those circumstances in PJM.

But there are a lot of buyers and there’s a lot of sellers. And certainly more than enough that more than we need to fill up our line.

Julien Dumoulin Smith: Got it. Excellent.

Michael Skelly: In fact sometimes we are often asked about chickens and eggs in our business. And the way we believe that gets resolved is as we get these lines permitted and as we make our way to the permitting process we find a lot more interest in our lines than we did five years ago when we were first starting. And this was much more conceptual than it is today.

Today we’ve got interconnect positions, routes on maps, regulatory approvals, etc., etc.; pretty good cost numbers - what is the lines cost, what does the State CDC equipment cost, etc. etc. What’s our transmission tariff going to be? We can have very serious discussions now that we’re getting closer to the finish line on permits than obviously than we could a few years ago.
Julien Dumoulin Smith: You’ve had some issues of late in the media around obtaining permits. What are the key gating items when it comes to permitting?

Michael Skelly: Yes. Well the key thing is either if it’s a federal authority or state authority - it all revolves around need. And different states have different definitions of what’s needed.

Julien Dumoulin Smith: How do you illustrate need in the context of just simply crossing states as you think about it?

Michael Skelly: Yes so you would point to the Clean Power Plan, point to RPSs, you can point to manufacturing job creation and you really articulate it. If it’s in Illinois for example - the need in Illinois is defined by enhancing a competitive electricity market. So that’s easier than some of the other statutes which are often 1950s era statutes.

And in many instances these statutes haven’t been tested for this particular purpose; so we’re a case of first impressions. And if we find that for a state statute we don’t need that need determination then we’re finding ourselves turning to federal authority and that need is more broadly defined than what are the needs of a particular state.

So if you look at the criteria under the various federal rules you’ll find that the delivery of clean energy and enhanced reliability etc. broadly speaking qualifies as need.

Julien Dumoulin Smith: And so I was going to try to summarize a lot of these questions that are coming in here. First how do you think about the risk or the utilization and the risk of under-utilization given the capacity for the wind? How do you fully round out these projects?

Michael Skelly: Yes, so that’s a great question. So if you look at line 17 we believe that people who subscribe to our line can use our line as they see fit, right. But we believe that when smart developers run the numbers they will see that the duration curve of a typical windfarm is such
that you can afford to shed the energy at the very top of your power production profile. **And overbuild a little bit. So you’ll overbuild to the tune of around 15 to 20%.**

And if you do you’ll optimize around your transmission capacity charge and you’ll fill up the line a little bit better. So that are **lines we expect will run at a capacity utilization rate of around 60%**. And just as solar costs keep coming down we’re actually beginning to think what would it mean to have solar at the end of the line because, as you probably know, the wind blows a little bit more at night. So that frees up some capacity during the daytime.

And if that were the case we’d be taking that 60% capacity and run it a little bit higher. And **60% utilization on a transmission line is actually quite high**. Most transmission is rarely used at its full capacity. But to the extent that we can work with our producers to get that number up, then that brings their per kilowatt hour cost down; which we think is good for them and good for their customers.

**Julien Dumoulin Smith:** How do you think about the collateral for financing these projects and the all-in cost considerations; I suppose getting a little bit of push-back on the cost of 2-1/2 cents when you consider in the interest costs. You know, the cumulative cost involved with the project. And this is what is the collateral involved. I suppose that’s the other side of it.

**Michael Skelly:** Yes, so what’s the credit? Well obviously if we’re delivering to a more traditional market then what we believe will happen is; if it’s a load-serving entity buying capacity on a line to get access to the resource, those are assets with pretty good credit.

On the wind production side - we’re going to have a variety of arrangements there. But generally we expect that it will be fairly large developers who are buying capacity on the line because of the very considerations that you point out. You’re going to need strong credit because we’re going to need strong credit behind our line in order to support our financing.
And that is a big topic of discussion as we’re working through these precedent agreements with different developers.

Julien Dumoulin Smith: We’re getting some questions here around your experience in developing projects and how this might apply to the competitive processes for transmission. First, have you evaluated participating in these projects or these processes using your project?

And do you see a robust number of competitors in your field - i.e. is merchant transmission a viable, competitive factor today in your view? Or is it just so high risk that you don’t really face too many folks out there?

Michael Skelly: So in our particular business of merchant transmission, there’s not that many people trying to do what we’re trying to do. The most similar project is probably Transatlantic Express which goes from Wyoming to Vegas. That’s also has multi-year development process, tens of millions of dollars. But there’s not a whole raft of companies doing what - or trying to do what we’re trying to do.

In terms of FERC order 1000, our projects don’t fit inside a national or even an interconnect-wide planning process, that says SPP get together with MISO, get together with PJM in order to plan out the grid. All the studies of the grid that are out there point to the fact that if you want a lot of renewable energy that HVDC technology’s the right way to go. In terms of FERC order 1000 we haven’t spent a lot of time on that. Our general impression is that there is more peace and light in that particular space. So there’s a lot of companies which are developing their independent transmissions. And in many instances this is for defensive reasons because they want to make sure that nobody else comes into their territory.

It’s feels like a difficult business for a couple of reasons. One, it’s the advantages of incumbency are huge. There’s not that many - the opportunity set is somewhat limited. We’ve heard a lot about FERC order 1000 for a few years now and we’ve only seen a few hundred million dollars’ worth of projects.

As you compare that to the size of some of the companies chasing these opportunities, there is a
mismatch there. So broadly speaking we think it’s a good idea, but transmission is not yet a wide-open competitive field that you see well in other countries; and in terms of what I think for us expectation was that you’d see a lot more activity. We just haven’t really seen a whole lot of that.

Julien Dumoulin Smith: How much of the total capacity of a line can a single developer take without violating the first open act of this requirement?

Michael Skelly: Yes so I’d need to double check that but I’m not aware of a limitation on how much one customer could take on the line. So if somebody came along and said hey I want to subscribe the whole thing, I think - if there’s anybody on the call like that I’ll give you my cell phone. But I’m not aware of such restrictions.

FERC has over the last few years introduced or promulgated a few rules that make life a little bit easier for us in terms of affiliate relationship. It used to be that FERC wanted you to only subscribe 60% of the line and leave the rest of it to open access. Now FERC is comfortable with 100% of the line being subscribed, etc.

So generally speaking I think there’s interest in the FERC in seeing more lines like ours get built. And they’re aware that to the extent there’s flexibility in those rules it will help us get the job done. And we have negotiated rate authority on the different projects today.

Julien Dumoulin Smith: How do you take into account the variability in the energy production of revenues given that you’re selling upon a fixed basis? Do you provide any buffer to the commodity exposure for off-takers here or really off-takers paying you a fixed fee?

Michael Skelly: Yes. So in terms of variability they vary with the wind. And as you know all the RTOs or utilities really that have tried to integrate a lot of wind have been very successful in doing so.

I’m in Houston and we have days in where we’re getting more than 1/3 of our electricity from wind. And
our costs to keep the lights on and everything works just fine. SPP and MISO, they regularly get into the 30 even 40% wind and manage the grid just fine.

So we don’t think that our delivering to PJM or the Southeast or whatever is going to create problems or challenges that can’t be dealt with.

The other thing that I would point out on variability - if you look at Slide 16, one of the advantages of long distance transfer of renewable energies - we effectively export the variability from say Kansas to Indiana. So we will pick up wind in Western Kansas, deliver it to Indiana. And as you know there’s some wind in Indiana. However, there’s zero correlation between when the wind blow in Kansas and when it blows in Indiana. That lack of any positive correlation is actually quite helpful in terms of integrating the wind. What you would want in a perfect world, you’d have a grid that could take a variable resource and move it anywhere else in the country because that national variability would translate into lower integration costs on a system-wide basis.

So we think of that as being as an advantage to what we’re doing as opposed to an AC solution. If you’re using an AC line - your variability goes directly into whatever’s happening on your local AC grid.

Julien Dumoulin Smith: To what extent are you at risk from a credit perspective, the extent to which that there’s a low wind year and what happens in the instance that this is unable to meet the fixed charge? How do you think about that risk?

Michael Skelly: Yes, so the wind producers will sell capacity on a kilowatt month basis. So that risk will be - essentially what you’re doing is you’re creating a fixed cost for the wind developers. And they’ll have to finance their project appropriately.

Julien Dumoulin Smith: To what extent is it a senior obligation right now and where do you stand in terms of the obligation back log?

Michael Skelly: Yes so we’re having that discussion right now. And we’ll see where it all ends up. But we think that lenders will
understand that if they’re lending to a project and it has no way to get to market, even if they foreclose, they’re going to need transmission service.

So we feel like we ought to end up in a pretty good spot in that discussion. But we’re living that today. We’re having those discussions right now.

Julien Dumoulin Smith: What is your ideal capital structure? If you think about it through the course of development; I suppose initially development capital you’re 100% equity? How do you think about the evolution of that?

Michael Skelly: So it’s obviously 100% development capital right now. So that’s all equity. We think that as we sign up capacity we’ll have more strategic interest as we turn up capacity and as we get permitting milestone and interconnect milestones taken care of.

And at that point we’ll be in the infrastructure world and we think we’ll be in opportunity to upgrade our interest to strategics and other utilities along the route. It might not be so keen on taking regulatory risks for an adjacent state or an unproven authority. But once those are taken care of they might be interested in participating.

And then as we go into construction we think it’s about 50/50 debt equity. And once a project is online you could be 75/25 debt equity.

Julien Dumoulin Smith: Where do you see pricing today just in terms of the cost of debt on the project? Is it too different in terms of the debt on these merchant projects once it’s actually got an off-taker?

Michael Skelly: No, we think it’s pretty cheap.
Julien Dumoulin Smith: How big do you see this market becoming and where are the principle areas of focus for these kinds of developments? And perhaps let me just try to paraphrase back what I heard earlier - your primary focus is east/west projects delivering into the Eastern markets, be it the Northeast, the Mid-Atlantic or the Southeast from Midwest projects.

And then secondarily what is the magnitude and timeframe for this project to come to fruition?

Michael Skelly: Yes. So to your first question, we think that if we’re successful then others will follow. If you look at the dimensions of the challenge in terms of decarbonizing the electric power sector, you need to do not just our lines, but a bunch more. And another whole set of AC upgrades.

And so we think the market could be in the billions of dollars per year but it does need to get proven out and that’s what we’re trying to get done.

In terms of timeframes, I would say that our fastest project would be the Plains Eastern Project and that goes from the panhandle of Oklahoma to the Southeast. We expect there’ll be a decision from the Department of Energy by the end of this year. DOE has put us on their Website

That project again will deliver 500MW to Arkansas and then 3,500MW to TVA. Once we get permits in hand we’ll spend a lot of 2016 getting all the commercial pieces put together and begin construction in 2017 so that we’re online. And it’s close to three years of construction so we will be online in early to mid-2020. And if and when that happens, it would facilitate if you do a bit of an overbuild on the generation side, 4500MW of wind and deliver; with deliveries again to Arkansas and the TVA system.

Julien Dumoulin Smith: Thank you very much Michael for taking the time to chat with us. Thank you all for listening. And with that we’ll talk to everyone next week. Thank you.

Michael Skelly: Thank you.
Statement of Risk

Risks for Utilities and Independent Power Producers (IPPs) primarily relate to volatile commodity prices for power, natural gas, and coal. Risks to IPPs also stem from load variability, and operational risk in running these facilities. Rising coal and, to a certain extent, uranium prices could pressure margins as the fuel hedges roll off Competitive Integratets. 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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<th>IB Services²</th>
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Source: UBS. Rating allocations are as of 30 June 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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UBS Securities LLC: Julien Dumoulin-Smith; Michael Weinstein; Paul Zimbardo.
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Source: UBS. All prices as of local market close.

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#### Eversource Energy (US$)

![Graph of Eversource Energy stock price and price target]

Source: UBS; as of 27 Aug 2015

#### ITC Holdings Corp (US$)

![Graph of ITC Holdings Corp stock price and price target]

Source: UBS; as of 27 Aug 2015