DEVELOPING RENEWABLE ENERGY PPAS

RECOMMENDATIONS FROM THE EXPERTS

With insights from:

- *The National Rural Electric Cooperative Association*
- *Dairyland Power Cooperative*
- *Poudre Valley REA*
- *D.E. Shaw & Co.*
- *Luminate LLC*
- *McGuireWoods LLP*
- *GE Wind*

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DEVELOPING RENEWABLE ENERGY PPAS

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RECOMMENDATIONS FROM THE EXPERTS

FEBRUARY 2017

CoBank's Power, Energy, and Water Center of Excellence is pleased to present seven interviews that explore the process of developing and entering into a renewable energy PPA. Each interview provides the perspective of a different stakeholder who plays a critical role in ensuring the successful execution of a PPA.

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CoBank has eight Centers of Excellence that serve as vehicles for identifying and analyzing strategic challenges, risks, and opportunities in all the major industries served by CoBank. Each COE is comprised of CoBank associates that are experts in their respective industries. The members of the Power, Energy, and Water Center of Excellence played an integral role in developing the series of interviews contained within this booklet.

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EXECUTIVE SUMMARY

Developing Renewable Energy PPAs: Recommendations from the Experts

By **TAYLOR GUNN,**
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CoBank's Knowledge Exchange Division,
covering the Power, Energy, and Water Industries.

As the cost of renewable energy continues to decline and it becomes more competitive with other power sources, electric cooperatives are turning increasingly to low-cost renewable energy to help meet their members' power requirements. In lieu of building and owning these generation assets themselves, many are executing long-term power purchase agreements (PPAs) at contractually specified prices for renewable energy. This enables the cooperative to pass on a number of material risks to the developer including construction, operating performance and maintenance.

Structuring an effective PPA requires complex, and highly technical negotiations aimed at aligning the interests of multiple stakeholders. For those electric cooperatives that have limited experience in developing PPAs for renewable energy, this narrative is intended to provide guidance. In order to facilitate this, we conducted interviews with seven individuals who have been involved, in different capacities, in the process of developing well-structured renewable energy PPAs. This series of interviews contains transcriptions of all seven interviews. These interviews highlight the experiences of other electric cooperatives and shed light on the crucial roles played by the various stakeholders involved in the process of developing renewable energy PPAs.

Competitive renewable energy prices have caught the attention of electric cooperatives across the country. Average PPA prices for wind energy from projects located in the interior of the country were close to $20 per megawatt-hour (MWh) in early 2016. Comparatively, the 2016 average on-peak wholesale energy price in the Midcontinent Independent System Operator (MISO) was $35/MWh. Similarly, the prices for long-term solar PPAs that were executed in early 2016 were below $50/MWh in every region of the U.S. with the exception of the Midwest. Solar projects in Texas and California are consistently priced below $40/MWh.

Going forward, declining prices of both wind and solar PPAs will continue to proliferate. Photovoltaic solar panels are becoming more efficient, inverters are becoming larger thereby requiring fewer for each project, and there is higher voltage architecture on utility-scale projects to allow for greater electric energy output while reducing the balance-of-system costs. The cost of wind energy continues to fall due to system-wide improvements. For example, improved construction techniques and materials result in longer blades, which require taller towers and larger rotors. Larger rotors result in blades that spin slower, which have driven huge advances in gear technology.

> *A well-structured PPA is the mechanism that brings all counterparties into alignment.*

An independent power producer (IPP) will usually serve as the key counterparty to develop the PPA, build and then operate the project on a cooperative's behalf. One of the major benefits to the cooperative in executing a PPA with an IPP is that it enables cooperatives to reap the benefits provided by renewable tax credits through a lower PPA price. In addition, a PPA frees the electric cooperative from maintaining and operating an asset that might require expertise that does not exist within the organization.

Cooperatives can leverage reputable IPPs for extensive expertise in building, operating and maintaining renewable energy assets. IPPs drive additional value through their long-term relationships with vendors, contractors, engineers, and financiers. These relationships ensure that system components are delivered by top-tier manufacturers, and that the design and construction are completed by highly skilled engineering, procurement, and construction (EPC) firms. IPPs work closely with independent engineers (IE) throughout the life of a project, and maintain close working relationships with lenders and financiers that have the capability to deliver complex financing arrangements that help ensure a competitive PPA price.

This emphasis on long-term relationships will resonate with electric cooperatives. If they are not going to own an asset, electric cooperatives want to be sure they are working with a long-term partner that can deliver the required power over the useful life of the project. IPPs that have long-term ownership interests are vested in maintaining those assets and optimizing their output, and they want to be sure the off-taker has the ability to meet its contractual obligations. In this scenario, the goals and needs of the IPP and the electric cooperative align perfectly.

A well-structured PPA is the mechanism that brings all counterparties into alignment. Project finance deals are resource-intensive and require considerable time and effort to review all the contracts carefully, and understand how they work together with all the other contracts. As a result, experienced project finance attorneys are critical to all parties for negotiating a strong PPA. It is imperative for electric cooperatives that do not have in-house project finance counsel to engage with outside counsel early on in the process. Hiring project finance counsel ensures that experienced, knowledgeable people who understand the industry and the legal complexities of power projects provide a comprehensive review of the documentation and all pertinent issues to protect the cooperative's interests.

As the cost of renewable energy continues to decline, interest among electric cooperatives is likely to grow. The series of interview transcriptions contained in this booklet is intended to provide insight into the complex process of developing a renewable energy PPA. Readers will hopefully take away lessons learned from other electric cooperatives that have successfully executed renewable energy PPAs. In addition, industry experts discuss the technological advancements occurring in wind and solar that promise to reduce PPA prices further. Seasoned power project developers share their view on the market and provide insight into the relationship between IPPs and electric cooperatives. A leading independent engineer highlights the advancements in the solar industry and the pitfalls to avoid while in the design, permitting, financing, and construction phases of a renewable energy project. And finally, an expert power project finance lawyer articulates the most critical issues that frequently arise during PPA negotiations.

We realize that this body of knowledge may end up raising more questions than it answers, but it will certainly provide valuable insight to those electric cooperatives that are considering entering into a renewable energy PPA. Moreover, knowing what questions to ask should prove to be helpful in assisting electric cooperatives to climb up the learning curve.

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INTERVIEW 1:

The Role NRECA Plays in Promoting Renewable Energy Among its Members

CoBank's Sarah Tyree talks to **KIRK JOHNSON**, Senior Vice President of Government Relations, National Rural Electric Cooperative Association (NRECA).

Many electric cooperatives are incorporating more wind and solar into their long-term resource plans as the cost of renewable energy falls. In this interview, Sarah Tyree, Vice President of Government Affairs at CoBank, sat down with Kirk Johnson from NRECA to discuss what role renewable energy will play in meeting coop members' needs into the future, and also what role NRECA plays in supporting coops in the development of renewable energy.

Sarah Tyree: How is NRECA promoting the development of renewable energy?

Kirk Johnson: We have a number of our members who are interested in developing renewable energy projects – everything from large-scale wind and solar projects to hydro projects, to localized community-based solar projects, to helping individual consumers with things like roof-top solar.

What we try to do is to make a variety of tools and information available to our members so they can make the most informed decisions about what is right for their individual co-op, at any given point in time and at any given place across the country. It's about two fundamental cooperative principles – the fifth principle of education, training, and information and the fourth principle of autonomy and independence. On information and education, NRECA tries to be a resource providing a wide variety of information that our members can use. And then, recognizing the independence principle, we know that what works for a co-op in Arizona may or may not work for a co-op in North Dakota, which may be very different from what's needed in Vermont.

We try to make sure that our members have a good understanding of the different options, and are doing their best job to meet their member consumers' needs at home. We're promoting tools and information that can help our members think through how they want to proceed, especially with more and more interest growing particularly in the solar area in many parts of the country.

ST: How does NRECA think renewable energy can benefit co-ops?

KJ: There are a numerous examples where co-ops have developed renewable resources and it's been very good for the co-ops. The most extreme and obvious example is in Kauai, Hawaii, where the co-op previously had been running on all-diesel energy, which was very expensive

> *The intermittency of renewable resources poses another challenge.*

and subject to supply constraints. They have moved over to solar energy with battery storage that has helped them reduce their costs. It was a very cost-effective, affordable solution for Kauai.

In places on the Great Plains, members have developed wind resources that have benefitted land owners – the member-consumers – where those turbines are placed. They've also helped meet membership demand and interest in rural energy. That's partly why we helped establish the National Renewable Cooperative Organization many years ago and why our members keep looking at those different options. It's all about what's best for any individual co-operative, and renewables definitely can play a part in helping to meet our membership's needs. But also to meet state requirements or to head off state requirements, and to demonstrate to state legislatures, governors, etcetera that we do not need to have that extra layer of government regulation – that our model of self regulation is very successful. We do whatever our members want and need us to do.

ST: What are some of the challenges posed by renewable energy development?

KJ: As with any kind of energy development, there are always challenges. You might have a consumer desire for renewable resources in a place where they're just not available. Florida does not have really good wind resources; so if member-consumers in Florida wanted wind energy, it would have to be imported, and transmission issues would then need to be addressed. In some areas, people don't view a wind turbine as something beautiful – they view it instead as an eyesore. Being cognizant of that not-in-my-backyard phenomenon is important.

The intermittency of renewable resources poses another challenge. You can only have solar power while the sun is shining, and you can only have wind power when the wind is blowing. With battery technology advancing, renewable energy storage may help deal with that intermittency. Co-ops must also make sure they've got the right backup generation in place to make sure that if the wind stops blowing or the sun goes down, energy will keep on flowing.

And then financing for renewable energy projects has sometimes been a hurdle. That is in part due to the fact that co-ops are tax-exempt, not-for-profit entities. Our members therefore cannot take advantage of the renewable energy tax credits. So we had to come up with some other financing models and mechanisms.

ST: How can co-ops engage with NRECA to learn about renewable energy development?

KJ: We provide a variety of opportunities to disseminate information about renewable resources. At nearly every conference that we've sponsored over the past decade, we've talked in one way or another about renewable resources. One of the most beneficial services we can provide for our members is helping to ensure that there is peer-to-peer learning – that a co-op in one state can learn from the experiences of another co-op that has worked on a similar project. We try to make sure that people who have gone through the energy and the effort have a chance to share that information and knowledge with their peers around the country.

We also provide more technical information through such things as our distributed generation tool kit, which we update periodically. We try to make sure that this isn't just about poles, wires, wind turbines, and solar panels, but that it's also about making sure you're communicating effectively with your member consumers, with you're local elected officials, with members, or with your congressional delegation – to make sure that everyone has a good understanding. We try to make sure that people have the tools available from us, to help meet some of those needs when they are going about the business of thinking about developing a renewable energy project.

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> *Our members are stepping up to that challenge and leading in community solar projects.*

ST: What tools does NRECA offer to co-ops for developing renewable energy?

KJ: I point heavily to the distributed generation tool kit, which can be very helpful when looking at distributed energy resources. We have also begun what we're calling the Community Storage Initiative, which is all about finding ways to help deal with that intermittency issue by being able to store energy. We've done that for a long time with our water heater programs, which is an energy storage opportunity, and there may be other ways to do that. And then some communication tools like Straight Talk and other items that we develop. There are many other tools that come out of different departments and divisions of NRECA.

ST: Can you elaborate about Straight Talk?

KJ: Straight Talk is a communications tool where we provide information to communications professionals about the best ways to talk about the changes that co-ops are making – to be proactive and positive in talking about what cooperatives are doing. It's a way that we can help communicators and co-ops make sure that they can talk about the important issues and have a broader perspective about those issues.

ST: What role will renewable energy play in helping co-ops meet their members' energy demands in the future?

KJ: I wish my crystal ball was perfectly clear on that question, and I could give a really good forecast. Everybody recognizes that renewable energy will continue to play a growing role in the energy mix across the country as the costs of wind and solar have come down and as we have been able to deal with the intermittency issues and as storage comes more online. Our members are stepping up to that challenge and leading in community solar projects. So rather than having a solar panel on individual homeowners' roofs, the homeowner can get that same benefit of having the solar power they want by doing it from a place collected by the cooperative. Homeowners don't have to worry about the maintenance of several solar panels on their roof, and they gain by getting some economies of scale from those larger-scale projects. Those are the things that we see, definitely continuing to grow moving forward, and making sure that our members can meet those changing needs that are coming from member consumers at the end of the line. ■

KIRK JOHNSON *is Senior Vice President of Government Relations at the National Rural Electric Cooperative Association (NRECA). He and his team are responsible for formulating legislative and regulatory positions on issues important to cooperatives and developing and implementing strategies to advocate those positions before Congress and federal agencies. The team is also responsible for building the political strength of electric cooperatives through ACRE® (the Action Committee for Rural Electrification – a top-100 PAC), a strong grassroots program, and educating NRECA's membership on legislative and regulatory proposals that will impact co-op member-consumers.*

Kirk has spent over two decades working on energy and environmental issues in Washington, D.C. Prior to joining NRECA in 2001, Kirk worked for U.S. Senator Kent Conrad for 9 years, serving as the Senator's energy, environment, and natural resources advisor.

Kirk is a native North Dakotan, received his BA in Political Science from Concordia College (Moorhead, MN), and attended graduate school at the University of Minnesota.

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INTERVIEW 2:

Developing a Renewable Energy PPA from the Perspective of a G&T

CoBank's John Kemper talks to **ED BOWEN**, Director of Financial Management, and **RON FRANZ**, Manager of Wholesale Services and Resource Planning, both of Dairyland Power Cooperative.

Generation and transmission (G&T) cooperatives possess extensive knowledge and expertise in entering into PPAs, acquired mostly from their past purchases of energy from fossil fuel generating units. They are quickly becoming equally expert at negotiating PPAs for renewable energy, largely from wind and solar assets.

John Kemper from CoBank's Power, Energy, and Utilities Division recently sat down with Ed Bowen and Ron Franz from Dairyland Cooperative to discuss their experience in developing and executing renewable energy PPAs as an off-taker.

John Kemper: What analytical process did Dairyland go through to forecast its generation mix in the future?

Ron Franz: I'll take a step back. Our Board of Directors pulled together its strategic plan with input from staff, as needed. One of their key goals coming out of the board planning activity was to diversify, as long as we can do it in a cost-effective manner. With that background, Dairyland set out with a mandate to look at ways to diversify our portfolio using a least-cost method over multiple future scenarios. The heart of integrated resource planning is the use of nodal and zonal security constrained economic dispatch models. We conduct those studies mostly in-house, but we do go external for consultant help for things such as a nodal security constrained economic dispatch.

Then, we utilize the request for proposal (RFP) process, which is what we're talking about today. Our planning process results in a preferred power supply plan, and Dairyland takes that plan and looks at it periodically against different future scenarios. For instance, Dairyland considers low-gas, high-gas base case, along with a Clean Power Plan (CPP) scenario. What we're trying to find is a plan that has the lowest cost under numerous future scenarios. That's the goal we keep in mind when we formulate our preferred power supply plan. Once the final plan is approved, we issue RFPs to fill slots that we haven't already filled with previous RFPs.

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> *What we're trying to do is diversify but not raise the cost of the overall portfolio.*

JK: How did you go about determining these different scenarios? Are they just standard utility-type scenarios, or were there any special cases that the Dairyland team derived?

RF: They're both. We use natural gas and power pricing scenarios that are utility standard, but then we shape them for our own load and our own resources. We use some internal and external resources for coming up with projected fuel costs and other variable operating costs. We have all of our fixed cost components that we know internally for our existing portfolio. What we're trying to do is diversify but not raise the cost of the overall portfolio. Multiple departments within Dairyland participate in formulating future scenarios for the planning process. If the scenario analysis results in unreasonable economics, we'll revisit and look to see if there are ways to tweak some of the assumed resource decisions within the plan.

JK: Did you have different price points in developing your scenarios?

RF: Yes. We have a low-gas, base case, high-gas and then, a stringent environmental look that we use to inform the modeling.

JK: Were gas prices the driving factor rather than wind capacities or solar capacities?

RF: Correct. Over our planning period, right now, we're still using the historic correlation between market prices and natural gas prices and applying the market heat rate by season to look at how those play out in the electricity market world. We do use nearer-term information to inform our PROMOD model, which is what we use to model the economic dispatch of Dairyland's generation assets. The model has incorporated some of the more recent changes with wind integration, but we're still seeing the historic correlations between gas and power prices hold up fairly well, overall.

Our load forecast is redone every other year using our econometric model with input from our 25 Distribution Cooperatives. Included in that forecast is penetration of things such as load management, and behind-the-meter or customer-owned generation sources, which help to inform that load forecast. We also have a good historic energy efficiency program and that's built into that load forecast as well.

JK: Do you think that Dairyland has an unusual load curve?

RF: Yes, I think we do. We have a later peak than our IOU neighbors. In the winter, we still have that double peak in the morning and then a late afternoon or early evening peak. In the summer, it seems like it's trending more toward a load buildup, but the buildup seems to peak a little bit later than the MISO footprint does, as a whole.

JK: It sounds as though in your process, you've looked at the future market fundamentals. Is there anything that jumped out at you, down the road that you needed to take into consideration in terms of your generation mix?

RF: The uncertainty surrounding the CPP is the biggest one. That has the potential, depending on how it all plays out, to be a step change in the forward forecast. We are uncertain on how the CPP will affect market prices, but we look at it as an added cost throughout the footprint based on carbon dioxide (CO2) emissions. That step change could change the cost of generation which in turn can pressure the net cost to serve Dairyland's load. The CPP and the tax credits for solar and wind probably pushed us into taking a little earlier action on major renewable energy purchases. We are actively looking to be at approximately 18 percent wind and 25 percent renewable energy generation by 2025. We're looking pretty hard at natural gas-fired generation as well.

JK: Can you give a forecast on high natural gas prices for your nodes?

RF: We don't have a forecast that we are willing to share, other than the general trend. We see natural gas prices remaining fairly flat going forward. Over the past couple

> *I don't think we have a bias on ownership, versus PPA. It is driven by what results in the lowest cost.*

of years, forward prices have flattened more than we expected. The wild card is what happens with fracking down the road. Could there be political momentum to significantly change the regulations for fracking? Other than that, we see flatter load growth and a small increase in natural gas prices over the long-term. Even our base case is a bit lower on forward gas than it was a couple of years ago.

JK: What are the subjective and quantitative factors that were used to assess whether Dairyland should own a renewable generation asset versus entering into a PPA?

RF: From our standpoint, it's not overly complicated. We're trying to achieve the most reasonable levalized costs on a net basis to serve load over the planning period. That's from a capacity and energy standpoint – being able to cover our MISO-required capacity – we're in Zone 1 and Zone 2. On a net basis, after making the energy sales, we try to have the lowest cost. I don't think we have a bias on ownership, versus PPA. It is driven by what results in the lowest cost. Given the production tax credits, PPAs have been the preferred path for our renewable build out.

JK: In order to build internal expertise for wind or solar, what does Dairyland have to do?

RF: If you're going to own wind or solar generation assets, you need internal employees who have experience specific to those technologies. Right now, the developers build and own the majority of wind and solar projects, along with the proper equipment and expertise to operate these assets. It's made the most sense for Dairyland to enter into PPAs, especially given the tax credits.

JK: Dairyland is a not-for-profit, non-taxable entity. Does it make more sense for renewable developers to utilize the tax benefits and pass along to you a lower cost of energy?

RF: That's exactly right.

JK: What are the key subjective and quantitative factors that lead to selecting the PPA alternative? Is it cost, cost, cost?

RF: Yes, it is cost. There's no question. The key driver is the levelized cost to serve load. We're looking for the lowest cost resource that fits within our diversified preferred power supply plan.

JK: What are the most important items in developing an RFP for a PPA?

RF: We conduct our RFP process with cross-functional internal groups that focus on environmental targets, economics, developer tax credits, and developer expertise. All of them are key items to look at. Then once an RFP is awarded, negotiation of the PPA contract is of utmost importance.

JK: Ed, can you comment on looking at the credit-worthiness of the developer? Can you tell us what steps you go through to analyze developer credit-worthiness or counter-party risk?

Edward Bowen: When we're looking at developers, we start with a general overview of how the credit agencies rate these entities or their parent entities. Then we'll complete an internal analysis of the entity's financials to make sure that we're comfortable both with how they're structured financially but also with how they're structured from the corporate view, as well. Typically, we also look at whether they're SUGs, LLCs, and how all the pieces fit together – all impact our decision on the credit side.

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JK: Do PPA negotiations typically track the RFP, or are there some unexpected twists?

RF: There are always some twists and curves. We've done a fair number of RFPs, and I would say the biggest change – since let's go back to pre-2010 – is the use of dispatchable intermittent resources in MISO. In other words, you're able to put in a bid and the intermittent resource may get dispatched based on nodal economics through the market model. What that does is, it creates language in the PPA addressing curtailment, how much and who pays for what risk relative to curtailment and compensation for production tax credits. Those have been the stickiest points we've had in recent PPA discussions because they're so important to both parties.

JK: Can you comment on how contentious the issue of curtailment might have been in your negotiations?

RF: I don't think "contentious" is capturing it, but it is complicated because you have all the different curtailment scenarios to think through. Is it an environmental curtailment, or a site-specific curtailment that the developer may or may not have known about when pulling the project together? Is it purely an economic benefit of curtailment? The analysis takes a lot of time. Developers and lenders weigh in on curtailment risks to make sure the project meets cash flow requirements.

JK: Can you give us a sense of how you rank the most critical issues during PPA negotiations? Obviously, initial price is important but what about price escalators, purchase options after the tax credits are gone, and default provisions?

EB: It's difficult to rank issues in importance because as we're pulling the PPA together, we may give on one issue but take a harder line on another issue. The thing we keep in mind is looking at the PPA from a big picture standpoint. Does the PPA provide what we need, and are we comfortable with the counterparty and risks that would be associated with the counterparty? That comfort level is a key driver. As we mentioned before, price is important. We're a little indifferent on escalators, versus initial price and those things. The biggest driver is what the levelized cost of energy is when we model the project over the life of the PPA. The experience of the developer is very important. How is curtailment risk allocated? Availability of the resource and what language goes around that are important. The tax issue, as we said – production tax credits are very important. Overall, we're trying to procure the lowest levelized cost for serving load.

> *"The biggest driver is what the levelized cost of energy is when we model the project over the life of the PPA.*

JK: Can you provide some additional clarity on how Dairyland evaluates transmission curtailment? When you initially identify a project, do you rely on a third-party assessment from a market consultant? Or do you maintain a holistic view internally depending on the region and the language incorporated in the PPA? Does this change how you prioritize projects based on potential curtailment issues?

EB: We rely on both internal and external looks. If it's a project close or within our service territory, we have some very good historic knowledge. We also consider what projects are in MISO planning horizon, such as the large MVPs. On bigger projects, we have worked with third parties to assess congestion and some what-if scenarios. If this MVP gets built, what does it do? If it fails to get built, what does that do? We have done that, both internally and externally.

JK: What role does Dairyland's external counsel play in the development of RFPs and in the negotiations of the PPA?

RF: We have Wheeler, Van Sickle & Anderson work on all of our RFPs and PPAs. We rely heavily on their expertise.

They have expertise in contracts and contract formulation and extensive knowledge with excellent attorneys that bring very valuable support for contract negotiations. We don't do any contract negotiation without the benefit of Wheeler, Van Sickle & Anderson. Dairyland has a long history with Wheeler, Van Sickle & Anderson and is very happy with our relationship and the support they provide.

JK: Do you have any general advice for those who are less familiar with the process, when it comes to negotiating and entering into a PPA?

RF: One thing I suggest is working with National Renewables Cooperative Organization (NRCO). They are very helpful from a coop's standpoint when discussing renewable RFPs and PPAs. I also think it's very helpful to discuss with other coops that have worked on similar PPAs. Talking to others that have had experience and seen some of the pitfalls that can come along is a helpful way to start. If possible, start on a smaller project and move onto a larger one using the same technology. This slightly reduces the risk while still capturing all the negotiations and key points within the PPA.

EDWARD BOWEN *is Director of Financial Management for Dairyland Power Cooperative. He joined the company in December 2011 and is responsible for the treasury and enterprise risk management functions.*

Prior to Dairyland, Edward worked at the Federal Home Loan Bank of Indianapolis and Cinergy Corp. in the treasury and global risk management areas. Edward received his Bachelor of Business Administration with a major in Finance from Cleveland State University and his Master of Business Administration with a major in Finance from Xavier University. He is a CFA® charterholder.

RONALD FRANZ *is Manager of Wholesale Services and Resource Planning at Dairyland Power Cooperative. He joined the company in 1998 as a Performance Technician at Dairyland's Alma Generating Site. In 2008, Ron began working within the Resource Planning department and was promoted to Manager of Wholesale Services and Resource Planning in 2013. As a member of Dairyland's team, Ron works extensively with investor-owned utilities, municipals, generation and transmission cooperatives and distribution cooperatives. Ron has participated in negotiations and the management of power purchase agreements, wholesale power contracts and generation projects. In addition, Ron works on regulatory matters in the four states where Dairyland provides generation and transmission service.*

Ron earned dual Bachelor's degrees in Biology and Chemistry from the University of St. Thomas and attended the School of Public Health at the University of Minnesota, where he worked as a Graduate Research Assistant studying the interaction of PCBs in the Great Lakes. Ron recently finished a six-year commitment as the cooperative representative on the nonprofit board of the Midwest Renewable Energy Tracking System, where he served as the board's Vice President for three years.

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INTERVIEW 3:

How One Electric Distribution Coop Structured Its Renewable Energy PPA

CoBank's Graham Kaiser talks to **JEFF WADSWORTH**, President and CEO, Poudre Valley Rural Electric Association

As the cost of renewable energy continues to fall, many rural electric distribution cooperatives are making strategic decisions to incorporate more wind and solar into their long-term resource plans. CEOs and managers of electric cooperatives must consider many variables when deciding whether to enter into a Power Purchase Agreement (PPA) instead of building and owning a renewable energy asset.

The following interview between Graham Kaiser, Relationship Manager at CoBank, and Jeff Wadsworth, President & CEO of Poudre Valley Rural Electric Association in Colorado, sheds light on the factors that influenced the decisions made by Jeff and his team, and provides insight to the process they went through in negotiating their renewable energy PPA(s) and coordinating with their generation and transmission (G&T) provider.

Graham Kaiser: What has been the driver for renewable energy at Poudre Valley REA?

Jeff Wadsworth: We look to see if a renewable energy project is going to balance three important factors for us. Does it maintain reliability, is it economical, and does it conserve natural resources?

GK: What is your association's investment thesis for renewable energy?

JW: For renewable energy, like any other investment, we look at what is in the best interest for our membership. As a member-owned cooperative, we strive to deliver safe and affordable energy, as well as service to our members. The deciding factors for us to invest in renewable energy are; can we purchase renewable energy at a price that is competitive with our wholesale contract rate, is it local, and can it help us to continue delivering affordable and reliable energy.

GK: What considerations went into the build-or-buy decision, and were any third-party consultants used?

JW: I take it you mean whether we own and operate or whether we buy energy through a PPA. It was a no-brainer to look at the first renewable energy projects that we've done as turnkey PPAs. This allowed us to take advantage of the investment tax credits, and to rely on the developer for in-depth knowledge of what these systems are and how they run and

> *A very high level of coordination was required. We want to be a good partner with our G&T so we keep energy produced from our systems on the distribution system.*

operate. That took care of a lot of the engineering aspects after the meter. Before the meter, we did use third-party engineering studies to look at how it was going to impact our system. Due to our G&T requirements, it was important that the energy produced stayed on the local distribution grid and did not transfer to the bulk electric system. For us, it was a matter of us using a PPA to develop these projects in a way that was economic while ensuring a high level of reliability.

GK: What were the key factors that led to selecting the PPA alternative?

JW: At the end of the day, it was the investment tax credit. That was the biggest PPA decision. We started our first renewable project in late 2011, early 2012 – our first community solar ray. Having a turnkey PPA made the most sense for us.

GK: What level of coordination was required with your G&T?

JW: A very high level of coordination was required with our G&T. We have a very sound relationship with our G&T – Tri-State. Tri-State requires that the energy generated by all self-generation projects must be less than five percent of our total requirement for the PPA that we have with them. The biggest items to coordinate were ensuring the pricing from the G&T – from Tri-State – and that none of the self-generated energy can flow back onto the transmission system per Tri-State policies. We want to be a good partner with Tri-State so we keep energy produced from our systems on the distribution system.

GK: What went into the development of the request for information (RFI) and what were the most important items in the RFI?

JW: We wanted to be nimble, so we did more RFIs on pricing and negotiated with a few different firms based on their RFI process. That helped us bring the price down. When reviewing RFIs, we looked closely at the developer's history of successfully implementing and installing projects, as well as what type of technology they proposed for the solar arrays, what output were those solar arrays going to produce, and what type of inverters were going to be used. We also looked at how developers proposed to handle the operations and maintenance (O&M) once the solar array was built. Another important aspect was to ensure that sufficient funds would be available to handle the O&M for the remainder of the PPA term.

GK: You mentioned the various technologies that developers were proposing. Can you go into more detail around that? When you say technologies, what are you referring to?

JW: Some solar panels, depending on the technology, could be tracking – either single tracking or double tracking – or stationary. We wanted to know what's the cost difference – how much more would we have to pay upfront for some technologies, such as trackers, as they offer a higher efficiency for a higher cost. We looked at whether the additional cost made sense and was worthwhile. Each project is unique because even with higher efficiency, some projects would not pay for the additional costs for the technology over the life of the PPA.

GK: Did the PPA negotiation track to the RFI, and if not, what were the primary areas of contention?

JW: I don't know if I would use the word "contention," but the biggest points of discussion after the RFI was what our agreement to connect to our system looked like and what it entailed for the installer and the owner of the PPA, the protection devices needed, and what they needed to sign off on for our standards, and such. These discussions involved quite a bit of back-and-forth, and

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it's something that we weren't willing to compromise on, just from a safety aspect when it came to the protection devices and what that installment agreement looked like.

GK: In negotiating the terms of the PPA, what were the most important items for Poudre Valley REA?

JW: The overall price for the entire package over the term of the agreement was important. We didn't look at the initial price to say, okay, is this something we want to move forward with, or not. We have a long-term relationship with our G&T, Tri-State, and the pricing model that they were able to provide for us is long-term. We looked at a long-term approach over the life of the PPA to see if the pricing made sense. The overall pricing as well as the price escalators were something we looked into to make sure that the project cash flowed and made economic sense from a profit and loss (P&L) perspective.

The tax issues also were important to us. Not only for the investment tax credit so it could bring down the price of the PPA, but what that looked like to our individual members that were buying into the community solar array. We've moved onto some utility-scale solar for which the members' participation was not required; but for community solar, it was required. And so we wanted to be sure that our members could easily understand what their participation in the community solar project would mean for them. Now, as we move forward and look at our utility scale project – a purchase option is something that we value after the tax credits, after the six years have passed and believe that such an option adds to the financial instrument and to the economic value of the PPA.

GK: How receptive was your board to this project and, are they open to additional opportunities? What were the board's sensitive points?

JW: The board was the catalyst for these projects. They looked out and had some great vision of wanting to look at these projects. They wanted to make sure that they were economic over the life of the projects. That was very important to them. Our board and management are very open to additional opportunities that meet the pre-criteria – reliability, economics and conserving natural resources. Our sensitive points include safety, reliability, and affordability. If all those things align, it's a win-win from our perspective.

> *"We looked at a long-term approach over the life of the PPA to see if the pricing made sense.*

GK: To what extent was legal counsel involved?

JW: Legal was involved in the review of the contracts – the PPA contracts and any other ancillary agreements that we signed with our G&T, Tri-State, as well as the agreements that we had with our third-party engineer for the system impact study. They were very involved to ensure that our interests were well represented through the PPA and any other agreements we entered into.

GK: Were you able to use Poudre Valley's general counsel that you typically use, or did you have to hire some additional counsel that specialized in these PPA agreements?

JW: We were able to use our general counsel. We're blessed with a very seasoned general counsel. He has the needed background when it comes to the PPAs and understanding what needs to be in those for protection of the Association. We did not have to go outside because of the level of expertise that he brought. But if he had not had that expertise, we would have absolutely gone out and engaged another counsel. These contracts demand significant resources and there are risks associated with them. You want to make sure you get them right.

GK: What perspective can you share on financing for the project?

JW: Today, there are more and more financing alternatives that you can consider for renewable projects. The biggest thing when you are looking at doing these projects is to ensure that if you're able to do it yourself that you and/or your financing partners have the tax appetite.

Typically, cooperatives have no tax appetite – so it's critical to have a partner such as CoBank that can bring the tax appetite to ensure that you receive the optimal pricing. Make sure that you partner with a lender who has the appropriate background for these projects, and who has the financial capability to execute and ensure that the project is completed successfully. Those are most important considerations when it comes to everything that you look at when you're looking at financing options.

GK: Where do you see the market fundamentals going for future generation development? How does that tie into your long-term resource plan?

JW: I think the renewable energy markets will continue to expand. The cost of renewable energy continues to fall, tax credits are available for years to come, and there is a growing interest within our membership and across the country. One of the current biggest challenges with these renewable projects is the intermittent nature of these projects. As energy storage becomes more prominent, renewable sources are going to become more of a base-load energy source. I can foresee the market changing to a level when we look at our short and long-term resource and capital planning, it will incorporate battery applications with renewable generation.

JEFF WADSWORTH *is the President and CEO of Poudre Valley REA, a rural electric utility serving 41,000 meters in Northern Colorado. He has 20 years of experience in electric utilities, including as a financial consultant with KPMG, an International Financial, Tax and Auditing Firm, where he served as a Senior Audit Manager. He has worked directly with electric cooperatives for over ten years, the last four as CEO at Poudre Valley.*

A Colorado native, he attended Fort Lewis College in Durango, Colorado, where he earned degrees in Accounting and Economics. When not leading his cooperative, he spends time outdoors actively climbing the next fourteener with his family.

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INTERVIEW 4:

Partnering with an Independent Power Producer to Procure Renewable Energy

Justin Merkowitz of CoBank talks to **DAVID ZWILLINGER**, Managing Director, D. E. Shaw & Co., LP.

The strong relationships many independent power producers have with vendors, contractors, engineers, and financiers can drive significant value for electric cooperatives that decide to partner with IPPs. Moreover, IPPs that have long-term ownership interests in renewable energy assets align well with those electric cooperatives that want to procure clean and reliable power.

Justin Merkowitz with CoBank's Project Finance Division met with David Zwillinger from D. E. Shaw to discuss the value proposition of electric cooperatives partnering with IPPs in procuring renewable energy.

Justin Merkowitz: David, can you please provide a brief background of yourself and what the D.E. Shaw group's role is in the market?

David Zwillinger: I've been at the D. E. Shaw group since 2005, and we've invested over $600 million in renewable energy since that time. Over the years, we've purchased renewable energy companies and have been involved in the construction, ownership, and operation of dozens of individual solar and wind farms across North America. Our D. E. Shaw Renewable Investments (DESRI) business was started around 2010 as a way to invest in individual renewable projects, including wind and solar.

We think renewable energy projects provide high-quality assets, and we acquire projects from developers with the goal of taking them from medium- or late-stage development through financial close and operation.

Today, DESRI's portfolio has slightly more than 1,300 megawatts (MW) of aggregate capacity in wind and solar projects, all of which have long-term offtake agreements.

JM: Where do you see opportunities in the future for renewable energy development?

DZ: Most people don't realize how economically viable renewable energy has become over the last five to eight years. There is a replacement cycle happening in the United States, as aging power infrastructure built in the World War II-era needs to be replaced. Renewables are increasingly the lowest cost form of new energy construction and we expect that the cost of renewable power construction will continue to decline. In addition, unlike traditional

> *Renewables are increasingly the lowest cost form of new energy construction and we expect that the cost of renewable power construction will continue to decline.*

power plants, there are no feed stock costs and comparatively minimal risk to volatility in fuel prices. We think that renewables enable utilities to offer customers clean, green, and low-cost energy solutions.

JM: Is there anything unique about working with investor owned utilities or municipalities versus cooperatives when you're developing request for proposals (RFPs)?

DZ: The counterparties are usually trying to accomplish a similar objective: to procure reliable, affordable power for their customers. In some cases, there is also a renewable portfolio standard. In other cases, there are state or community objectives.

Investor-owned utilities are traditionally more constrained in the manner through which they proceed. That could mean having to go through a public utility commission (PUC) process, which often takes a long time and is a formalized process. With municipalities and coops, there is frequently more flexibility, which helps in responding to changes in the marketplace.

A project called Springbok II comes to mind as an example of where we effectively partnered with CoBank. We owned an earlier project called Springbok I in California. The Los Angeles Department of Water and Power (LADWP) decided they wanted more power, so the developer was able to secure an expansion with them a short time later. This is an example where we were able to get something done quickly, efficiently, and at a great price for LADWP.

As we've built on our success, we have seen more serious interest from coops and municipalities, particularly in regions where there hasn't been a ton of interest in renewable energy to date.

JM: If a cooperative wants to engage in an RFP, walk us through that process, and discuss the level of involvement from the independent power producer (IPP).

DZ: Oftentimes a coop will come to the conclusion that they need new generation, sometimes because their base load is growing as the local population expands, but more frequently for replacement of a retired unit. Each coop will have its own process, but usually a cooperative puts out an RFP based on what the cooperative is looking for in terms of size, scale, geographic region, and the date by which they need the power. We can then help a developer show financial viability and offer a competitive and attractive solution to the coop.

Coops require projects to be competitive on price, but they also want to be comfortable with the owners. When coops evaluate potential long-term owners, they are looking for someone with financial strength and a long-term outlook. As an example, we acquired a project where we posted a letter of credit for that developer the day the project signed the PPA, which demonstrated our financial commitment. In other instances the utility will only do business with a party that comes in with a long-term owner (like DESRI, for example).

JM: How have changing market dynamics such as increased competition, declining costs of modules, and lower availability of sites for viable projects changed your bidding strategy, and where do you see your bidding strategy going in the future?

DZ: It's a competitive marketplace. To succeed, we constantly need to refine our business model and try to forecast how we think the industry will evolve. We're seeing meaningful improvements in the technology, which translates to greater efficiency. Wind turbines today are meaningfully more efficient than they were only 3 or 4 years ago. The costs for solar projects are much

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lower than just a few years ago. We need to be mindful of what's going on in the marketplace and find good financing parties so that we can offer competitive capital.

JM: Do you work in somewhat of an advisory capacity when you're working with your counterparties and how do you help educate your counterparties on the technology?

DZ: We don't really operate in an advisory capacity. We're telling counterparties the price through what we are comfortable bidding factoring in the many factors that are required to get a project built – the cost to construct (EPC cost), rate of return on the debt and equity, financing for tax attributes. We're trying to work interactively with our counterparties to offer them the best solution that is also still feasible. We don't want to be in a position of offering a rate of return that is too low and risk being unable to deliver. It's ultimately a collaborative effort to provide a competitive proposal.

JM: Obviously price is usually first foremost on everybody's mind when negotiating a PPA. Discuss what other important items during PPA negotiation, and how do you allocate that risk between the seller and the off-taker to help preserve the project's overall financeability?

DZ: When PPA prices were much higher three or four years ago, we had to think a lot about price as an issue. Today, with current power prices, we of course still need to be competitive, but the differences between different offers could be very small, such as 25 or 50 cents. Other important variables include an ability to work with counterparties. The more sophisticated the coops and other off-takers are, the better it is overall. If we have a project that can bring in project finance, that's valuable. It's a good way of driving down power prices. We consider things like letter of credit requirements, commercial operation dates, and when a counterparty needs to have the power delivered by. These considerations are often becoming bigger issues, especially as the cost of power has come down.

> *When coops evaluate potential long-term owners, they are looking for someone with financial strength and a long-term outlook.*

If both the buyer and the seller work together to develop a solution jointly, that is going to help ensure that power is delivered efficiently and effectively for the length of the PPA.

JM: What are the criteria you look for to identify the appropriate technology and equipment for any given project?

DZ: We are generally in the business of owning these assets for a long time, so we focus on tier one technology. We're focused on traditional tier one suppliers and parties that will back their product. This is even more crucial for wind because windfarms have more big moving parts. We want long-term relationships with suppliers so we can do repeat business. We've used the same inverter on our last three or so projects and we have probably used that vendor six times previously. Having that type of relationship and trust is very important since these projects are not one-time sales, they are ongoing service relationships.

JM: What are you looking for in a qualified EPC and the independent engineer (IE)?

DZ: Over the last two years, we have consistently used the same few EPCs. There are many benefits: we save a tremendous amount of time negotiating the EPC agreement; our counterparty, lenders, and tax equity providers are comfortable because the EPC agreement has been through finance, legal, and independent engineering review; and, most importantly, the EPCs know this is a long-term relationship and value that. Things go wrong and things break in this business. It's not just having an EPC with a good warranty. They know we're an important client and they want to do more business with us in the future, so they fix things

proactively. They make sure our technology is optimized. It's a partnership with everyone sharing the same vision.

Today we work with the same few EPCs on new opportunities. We need to be fair on price to be competitive but we also want partners who are viewing each project as part of a broader relationship. If ten projects go well, the eleventh one might have some bumps. They understand it's a long-term relationship and they are willing to do everything it takes to make sure things run well, even when there are hiccups.

The IE side is a little more complicated. Each IE is a little different, providing less of standardized process than we would like. IEs are typically busy and teams seem to have a high turnover rate. Fortunately, this is less common for EPCs.

JM: If a coop wants to develop a project, what are the primary benefits of working with an IPP versus developing on balance sheet?

DZ: It's hard for me to believe somebody who is doing a project for the first time or the second time will be able to offer anywhere close to the terms we're going to be able to do. Let me give you a couple of examples. We believe we have a lot of panel-buying purchasing power. We have EPCs that are competitively bidding to win business. We've got multiple developers that we've worked with who we think can find a better site.

We have team members at every step of the process – obtaining the land, arranging the interconnect, purchasing panels and inverters, and finding great financing parties. The best way to offer low-cost power is to have a low cost of capital, use leverage on the project finance side, and utilize the most efficient tax equity. Finding professionals who seek out the cheapest way, the best way, and the most effective way to complete a project is ultimately the best way to develop an attractive asset.

JM: Are there certain markets or regions in the country that DESRI sees a larger opportunity set in, particularly as it pertains to the cooperatives? Does your marketing strategy change if a cooperative is rate regulated by a PUC, versus having board autonomy?

DZ: No, I think it's just a time process. As with many things, the more organized and prepared you are the more you can handle the different approaches. If you want power delivered to you in December 2017, a process that requires PUC approval is not practical. If you want power delivered to you in 2020, it doesn't matter one way or the other. The regulatory process is often the biggest driver of timing.

We've done projects that were PUC regulated and projects that were not, and we can make either process work. It honestly just comes down to the timeframe. Also, obviously it's easier doing a deal if you shake hands and when you leave you know you have a deal. However, we have fortunately not seen a lot of PUC objections on signed contracts.

JM: How do you see market fundamentals changing particularly post expiration of the ITC and PTC tax credits? Where do you see the opportunities, where do you see challenges in the market as it pertains to DESRI?

DZ: Our DESRI team is a small team; we're not a bureaucratic organization, which means we can be flexible. We've done projects with CoBank as small as 10 MWs and as large as 150 MWs. We think we're pretty good at adapting and adjusting. Depending on the situation we can move fast or slow and react to changes. What's challenging in the renewable business is the changing landscape. Tax credits expire and tax credits come back. Foreign export tariffs come in, and then those tariffs go away. Uncertainty is generally not a positive because it reduces company's ability to invest and its willingness to take on risk. There is always uncertainty—for example, what happens to renewable

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energy in light of the new administration, or changes in the public's desire for energy—and those are all things that could affect the rate of growth and the opportunities in the market. That uncertainty has driven the renewable industry. It has stops and starts. However, at DESRI, we have learned to manage the uncertainty by focusing on the core fundamentals of the renewable business: developing technology, relationships, and expertise. CoBank has been a valuable partner to DESRI as we've built this platform. We have been doing this for a long time and we believe that the opportunity set will continue to grow.

DAVID M. ZWILLINGER *is a managing director of D. E. Shaw & Co., L.P., and a member of the D. E. Shaw group's U.S. Private Equity investment unit. Mr. Zwillinger is currently focused on investments related to the development, ownership, and operation of renewable energy assets. Since 2012, his activities in those areas have focused on D. E. Shaw Renewable Investments ("DESRI"). DESRI manages investment vehicles that currently own and operate approximately 20 renewable energy projects across the United States.*

Prior to joining the D. E. Shaw group in 2005, Mr. Zwillinger was an associate at J.P. Morgan Partners, L.L.C., and previously was a member of Merrill Lynch & Co., Inc.'s mergers and acquisitions group. He currently serves on the board of managers of Bright Plain Renewable Energy, LLC, and on the board of directors of Franklin Holdings (Bermuda), Ltd. Mr. Zwillinger graduated summa cum laude from Rutgers College with a B.A. in economics and earned a B.S. in finance from Rutgers Business School.

INTERVIEW 5:

Insight from an Independent Engineer on Developing Power Projects

Matt Brill and Justin Merkowitz of CoBank talk to **CATHY GROVER**, Senior Vice President, Luminate LLC Management Consultants

Independent engineers play a critical role in virtually every phase of power project finance deals. The project owners, off-takers, and lenders all rely heavily on their un-biased expertise in permitting, design, construction, and financial evaluation.

Justin Merkowitz and Matt Brill with CoBank's Project Finance Division met with Cathy Grover from Luminate, a management consultancy that provides independent engineering services to the power sector, to discuss the process of developing a renewable energy project that meets all the requirements set forth in a PPA.

Justin Merkowitz: Cathy, can you give us a brief history of Luminate – how it was founded and what are its primary scope and expertise?

Cathy Grover: Absolutely, thank you for the opportunity. Luminate was formed in 2006 by long-time power project finance veterans. We cover the entire power spectrum, except for nuclear. We're a technically-based management consultancy, and we provide engineering, commercial, environmental and technical services in the energy markets.

Primarily, we are engaged as the independent engineer (IE), but we also represent project sponsors (i.e., owners) to advise in project development where the sponsor's goal is to secure debt, tax equity, senior debt, a land lease, or whatever it may be, to help finance the project.

With solar, in particular, we have reviewed upwards of 12 gigawatts (GW) of projects ranging from what I call the smallest of the small, to the largest of the large. We've looked at 10 KW-size projects, so aggregating 10 KW projects into a portfolio of a significant enough size to be able to place debt on that portfolio, up to the 550 MW Desert Sunlight project, which is a standalone utility-scale project.

JM: Can you speak to your background, your team's background and the training necessary to be an independent engineer in the field?

CG: I've spent 15 years in power project finance. The three original owners of Luminate are 25 year (plus) veterans. They began their career at the advent of the independent power producer (IPP). Luminate has a multi-discipline solar team on-

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staff, including Dr. Frank Vignola who heads the University of Oregon's Solar Resource Center. He has a PhD in Physics. He is a 30-year solar guy. We have a couple of electrical engineers with a background in electrical engineering solar design. They know the NEC Code inside and out. A couple of our team members have a pretty long history of evaluating resource data and applying that resource data to different modeling tools to forecast solar energy production. We also have civil engineers and a couple of environmental professionals in-house.

JM: What is the primary role of the IE in the early stage of the project development through construction?

CG: Traditionally, for solar projects, the IE begins by reviewing the financial model and all the assumptions and technical inputs in that model. Specifically, we analyze the project's electric energy generation and how it is contracted under an off-take arrangement. We also look at the operation and maintenance (O&M) expenses. We look carefully at what kind of data are available in order to evaluate and substantiate revenues and expenses in the financial model. During this review process, we leverage our technical expertise across the industry to try and identify risks and their magnitudes, as well as any optimization that can occur in project-related issues.

JM: Who are the primary counterparties that rely on the independent engineer?

CG: There are various stakeholders that rely on the IE report. The sponsor will rely on the IE report. We have also done sell-side advisory as well as buy-side advisory. So it could be somebody who's looking to sell a development project. It could also be somebody looking to buy a development project. Obviously, there may be lenders or investors who are involved. That could be through anything from short-term debt, construction lenders only, tax equity, long-term lease — it could be multiple parties. In any one engagement, we may have multiple parties, including the lender's in-house legal team who may want to rely on the IE report.

> *"The stakeholders all want to make sure that the project is going to generate the revenues as expected and that there is proper accounting of the expenses, as well as any risks that may be associated with a project.*

JM: Can you walk us through the key components of the IE's review of a project? What do you view as most critical to each of those particular counterparties, most notably the developer or sponsor, the off taker, and the lenders?

CG: I would say that the stakeholders are pretty well aligned when they're evaluating a project. They want to make sure that the project is going to generate the revenues as expected and that there is proper accounting of the expenses, as well as any risks that may be associated with a project. Obviously, risks can take many different forms, and it's somewhat project-specific. One of the things that we'll do in evaluating a project is look at the site suitability. That can include anything from how easy is it to access the site, how easily can you transport equipment to the site, what's the laydown area of the site, where is the site located, or is it co-located to an interconnection point. We'll also look at adjacent neighbors that may be hostile against the project company or a project owner. We also look at the sub-surface soil conditions with help from geotechnical reports to make sure the existing soils can support the proposed project design. Does the soil have boulders? Are you going to have to pre-drill any foundation system? Or, are there are any special considerations that might need to be taken into consideration for construction, especially, if there is construction lending.

We also look at environmental and permitting requirements. We'll make sure that the proper permits are in place, that the proper authorities with jurisdiction have been contacted, and that the project has received

the required regulatory approvals in order to proceed with construction and eventually into operation. We'll look to see if there are any – what I call – blackout periods in construction and/or operational considerations in the permitting documents. We'll next turn to system design and technology. We'll look at the technology that is planned to be deployed at the project. If it is an operating asset, we'll determine if there are any known issues, design considerations with certain pieces of equipment that need to be considered in forward-looking electric energy projections, and/or any kind of special considerations for operating and maintaining equipment. An example might be fixed- tilt versus tracker solar arrays. With a tracking system, there are more moving parts that potentially require additional monies to maintain the tracker system.

Associated with each site would be a specific solar resource and electric energy analysis. We'll look at the climate of the site and try to understand if there are any specific micro-climate conditions. For example, if you're on an island in Guam or Hawaii, you absolutely have to take into consideration micro climates. We'll forecast electric energy based not only on the solar resource but also the type of technology being installed, taking into account the reliability of the technology.

Another key item if you're constructing a plant is the engineering, procurement and construction agreement(s). If you have an owner-construct model or a fully-wrapped, single-source engineering, procurement, and construction (EPC) contract, we'll look at the quality of the construction provider and look at the various assets of the EPC arrangements. Everything from design considerations and design standards, to various schedule timing, milestones that need to be achieved by the EPC contractor, performance testing, and any damages associated with schedule and/or performance.

We also look at the O&M arrangements. Not only do we look at the O&M agreement, we also look at the quality of the O&M provider – whether or not they have site staff in the area. We look at the quality of the sponsor to understand how many operating assets they have on hand, if they're going to be performing any performance benchmarking in-house, or if they're subcontracting that out. We'll look at availabilities and uptime guarantees. We'll also look at how maintenance is to be performed. Is it proactive maintenance, is it reactive maintenance, etcetera.

We also look at the off-take arrangements and interconnection provisions to understand if there are any special considerations that need to be made in the design. If it's a new build, we determine if there are any network upgrades under the interconnection arrangement that need to be considered in the construction timeline. Last, but probably most important, we'll look at the financial model and we'll understand how all these previous topics support the financial model projections from electric energy and revenues to O&M expenses.

Matt Brill: What is the timeframe from start to finish? As a lender we become involved sometime after the IE has already started evaluating the project. How long is this process for a solar project?

CG: Once we begin our review, we can usually turn a draft report in 4 to 6 weeks if all of the key documents and key data are in place, whether the project is a new construct or an operating portfolio. Projects that are on the larger side – like the one I mentioned, 100 MW (plus) – we're definitely looking at 6, 7, or 8 weeks. Or, if you have a portfolio that consists of multiple projects – we just got done working on a portfolio with 15 projects – we were right at the 7 to 8 week mark to perform our full due diligence to turn a draft report. However, after a draft report is turned, sponsors always have comments. They always have verifications or want to understand if there are any items that have been identified that need to be mitigated. And then obviously any lender will have questions.

Usually, the back-and-forth with the owner and the lenders can be anywhere from 2 to 6 weeks, depending on how large the lending group is, and how many items there are that might need to be addressed in the IE report.

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JM: What are the characteristics of a strong EPC agreement?

CG: For a strong EPC agreement, whether it's with a true third party or the sponsor is going to self-construct, we're looking for what we call an arms-length arrangement that is fully wrapped. This means there is a single source in case there is any kind of issue that arises. We're looking for the contractor to have a resume of demonstrated performance at a similar scale. So, if the EPC is for a 50 MW project, we're looking to see if the contractor has built projects in the 40-60 MW range. If the contractor is going to be constructing rooftop facilities, we're looking for the contractor to have a resume where they have constructed rooftop facilities. We're looking for a contractor to have demonstrated performance, providing similar services at the scale contemplated for the engagement in the geographic region. If the project is in California, we want to see California experience because there may be union labor considerations.

With an arms-length arrangement, we want to see services provided by a date certain. There has to be a minimum level of performance demonstrated. Failure to meet this requirement places the contractor in default. There are also milestones that need to be achieved for mechanical, substantial and final completion. To the extent that the schedule or performance is not demonstrated, there are damages assessed to the contractor for which the contractor is required to pay or compensate the owner. Those damages need to be at, what I call, a market rate, so it's not just reimbursement for lost revenue, but also for any additional costs if the project development and/or construction goes longer than anticipated or if there are unanticipated performance issues.

We also look for a scope of work that is complete and well-defined. It should cover the various contractor deliverables – everything from design, O&M manuals, commissioning, testing, wrapping, performance – it's demonstration of the whole project, not just a subset of the project. That's what we're looking for in a strong EPC contract.

> *"For a strong EPC agreement, we're looking for what we call an arms-length arrangement that is fully wrapped.*

JM: When a developer or cooperative is looking at identifying an EPC, why might the lowest-cost option not necessarily be the best option?

CG: EPC prices will absolutely vary depending on your geographic location and the scale of the project. Even for a particular region, we have seen pricing vary. When comparing EPC contracts, it's looking at cashflow. How is that EPC contractor to be paid? What are the milestones that need to be achieved during construction on which the contractor will be paid? Oftentimes, the more risk that a contractor takes on, the more that contractor may want to be compensated. Therefore, we've seen very low-price EPC contracts where there is no requirement to demonstrate performance of the project nor is there any requirement to hit a certain scheduled completion date, and in fact if a scheduled completion date is missed, there's no recourse back to the contractor, either from a monetary perspective or from a contractual perspective that the EPC contractor might be in default. Therefore, sometimes, just being the lowest price EPC price may not be the best EPC.

JM: What is involved in the permitting process for developing a solar project? We've seen issues where development can run into significant delays. Can you talk about what's involved and how those lengthy delays can be avoided?

CG: In general, we look for local land use authorizations and zoning determinations. Local building permits, wetlands or jurisdictional water determination, construction storm water discharge permits and dust control permits. Specific permitting obligations can vary. For example, if you're building on school property sometimes you have to go to a local school board, and while it's not necessarily considered a permit, it's definitely considered an approval. Or, you have to

> *It's critical to have an understanding of the proposed land use, the permitting requirements, or any environmental obligations – and to have them early on in the process.*

get permission from the school board or the school designated authority in regards to your design.

We also see other permitting obligations regarding aviation if you're next to an airport. Wildlife permits may also be needed; for example, in certain parts of North Carolina, the long-eared bat is a threatened species. There could be water use permitting or requirements or other existing environmental conditions that may need to be considered and be permitted around. Almost everybody across the board, especially if you're a lender, requires a phase one environmental site assessment to understand if there's potential for any preexisting conditions. We've also seen studies above and beyond permitting that may be required, including cultural and archeological studies, wetland and jurisdictional water studies, and habitat studies.

JM: What have you gathered from the developers you've worked with to be best practices for successfully developing, building, and operating projects?

CG: Some developers that we have worked with have a very high success rate of getting projects built, which means they procure the land, they're able to get the requisite authorizations from the various authorities having jurisdiction, and they're able to execute at a reasonable cost in order to build the project so that they can own and operate it for the long-term, or to sell that project to another sponsor. It's critical to have an understanding of the proposed land use, the permitting requirements, or any environmental obligations – and to have them early on in the process. We have absolutely seen projects go far in development, and then the local city board will deny the construction permits because they don't like the location of where the project is going to be built. Understanding the location, understanding who may have a say in whether the project gets built, and then making sure that you have buy-in from all the stakeholders that are going to have to provide authorization to construct and authorization to permit. It is important to understand and address their concerns early on.

MB: We are seeing a lot of projects that have a very short window between the substantial or final completion date and the PPA sunset date. Sometimes it's difficult to win extended cure rights or changes to a PPA if you're off date. What has been your experience in solar development on that tight window before the PPA sunset date?

CG: We like to see a minimum of 3 months, but 6 months is preferred between your construction, maybe not final completion, but definitely substantial completion where you've demonstrated project performance and you're interconnecting and you've declared COD. We have been involved in a couple of financings where that period between substantial and sunset date under the PPA was 3 months. We've seen many projects meet or beat that 3 month window. We've been involved in a couple of projects where they cut it really close. For the ones that cut it really close, and I'm talking days or weeks, usually there was some issue with a permit that caused them to be delayed. The inspector came out and inspected and required a redesign of a certain element of the project, or there was a delay in getting a permit or in the permitting process, the owner hadn't taken into consideration some key element that delayed the initial delivery of the permit. That's where we've seen developers struggle when they have short duration construction.

MB: You know that there are ways to partially reach COD [i.e., the commercial operation date] under solar. You had discussed that with wind financing where you commission X number of turbines to reach your delivery date. Can you do the same with solar power?

CG: You can, but it can be more challenging depending on the PPA. For example, if you get into California, some of those PPAs require that if you declare commercial operation, you are declaring that the project can delivery at least 90 percent of the expected energy. And then,

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there could be a rolling 12-month or rolling 24-month expectation for delivery of electric energy. So when you declare COD, you want to make sure that you can at least reach the minimum generation requirement so that you're not in default under your PPA. Most PPAs you can declare parts of the plant at COD but, some PPAs require a certain threshold or a certain minimum of electric energy production in order to declare COD.

Some PPAs will let you reset. If you have to deliver 100 MW hours in a year when you get to COD, you have some PPAs that will allow you to reset that amount. So, you could reset it at say 80 MW hours if you weren't able to get the entire plant up and running. There's a mechanism within some PPAs that allows you to do that. But it depends on the PPA and also on the off-taker.

JM: We've observed over the last 5 to 10 years that the cost of solar has come down tremendously, and we're seeing solar at or near grid parity with other competing technologies. Talk about the impact of the cost-cutting measures on solar procurement. With these cost-cutting measures, have you seen any issues with quality control?

CG: A lot of times we automatically think falling module prices, which is huge. We're also seeing some cost-cutting measures with inverters in the way that inverters are built so that you can service them easier. We're also seeing higher and higher voltage architecture on utility-scale projects to allow for higher electric energy output while reducing the balance of system cost for ancillary equipment.

I'm going to start with modules and then I'll talk about inverters. In regards to modules, that's where we've seen a cost reduction. Today, modules are around 60 cents per watt. Next year, or within two years, they're expected to be in the 40 cents per watt range. They've come down significantly over the past 5 years. At the same time, we're seeing more attention paid not only to the standard testing, but also to the UL certification process and the IEC certification process, with certain lenders requiring testing above and beyond those standards. You hear about thresher tests or additional thermal cycle testing. If the modules are IEC certified, which is your industry standard module testing, almost every bankable module installed is IEC certified. That's a 200 thermal cycle testing unit. Some lenders are now coming back and saying they want to see 400 thermal cycles or 600 thermal cycles, which provides an idea of the longevity of the module and where any weak points in the manufacturing process might be when you start looking at failure rates versus thermal cycle testing.

What we've seen in the past 5 years is not only a cost reduction, but more attention paid to the third-party laboratory testing that's available, as well as several firms that provide manufacturing quality control services. There are several firms that you can contract with that have placed personnel in the module manufacturing facility that will spot check the quality of the module, whether it just be the facility itself. We've been involved in several jobs where a third party has been retained to inspect say 10 percent of the modules being manufactured at each of the facilities that are project-specific. They'll look at the welds, they'll look and see how it flash tests, they'll look to see if there's any visible cracks, and at the quality of construction. Even though we're seeing this race to bottom with prices, we're seeing a lot more effort put into third-party providers that can provide site-quality control, as well as a better understanding of what third-party laboratory testing has benefited, and what additional information that provides in regards to the quality of the module construction.

JM: Let's move onto inverters...

CG: There are a couple key differences in today's inverters from 5 years ago compared to current technology. Five years ago, whether it was utility scale or rooftop, it was a central inverter. Central inverters were 500 KW. You knew you were going to have to overhaul that inverter somewhere between year 10 and 15, and you were going to have to replace the whole IGBT, which is in essence the engine of the inverter.

Today, you see central inverters that range from 550 KW all the way up to 2, 3, or 4 MW. So there are bigger inverters and inverters where the IGBT is more compartmentalized so that if you have a failure in the IGBT you can replace that component and not the whole engine. There is also the deployment of string inverters

for rooftop or smaller distributed-generation systems. If you have a string inverter go out, you can still operate the facility at a very high level of performance until you have the opportunity to come around and replace that individual string inverter.

The inverter space is seeing some cost-cutting measures driven by larger inverters, thereby requiring fewer for any given project. Looking at the long-term costs of operation, we're seeing design considerations in the topology of the inverter engine. Lastly, from a design perspective, we're moving from the 600 volt systems of 5, 6, or 7 years ago to 1,000 volt systems. 1,000 volt systems today are now being replaced by 1,500 volt architecture systems at the utility scale. That provides some cost savings.

MB: In project financing in the market today, are you still seeing reserve accounts specifically designed to cover liquidity for purchases on this type of equipment after the warranty period? Do you recommend that it should be considered prior to the warranty period? Without pinning it down to specific numbers, what is the general market for reserves?

CG: As we've moved from what I call longer term debt lenders to more tax equity, there's a huge tax equity appetite. The tax equity is out to 5, 6, or 7 years and tends to place less emphasis on having a major maintenance reserve account, versus what I call senior debt, a lease arrangement, or longer term debt. I would say even a year or year and a half ago, almost everybody required a major maintenance reserve account. This means that by somewhere around year 10, 11, or 12, you had to reserve for your inverter overhaul. That was usually priced somewhere between $40 and $60 for KWAC, with a consideration of central inverters.

Today, depending on the lender and depending on the type of lending arrangement, the lender may or may not require a reserve account. When we look at it depending on the type of project, if you're using string inverters, you're not going to overhaul, you're going to replace. This is because you would spend just as much money in the time required to get to the site than you're going to spend on overhauling a single one-off string inverter.

We are seeing some consideration if you have a distributed generation (DG) facility that uses string inverters on how you reserve. Or if you just lump it in with your own end-reserve account, if you have a 6-month O&M reserve that provides some additional contingency or cushion on top of your forecast expense.

MB: Do you have fewer concerns regarding the costs associated with replacing and repairing inverter equipment than a few years ago?

CG: We are seeing some design changes that we think will help with realized expenses. Obviously, we're 10 years out in proving that theory. As an independent engineer, we look at the data that are available. Three years ago, we were recommending $40 to $60 per KWAC. Today, we're still recommending $40 to $60 per KWAC, and we are still recommending it as a reserve. That doesn't mean that there may be a slow change in philosophy. Inverters have changed, they're becoming easier to maintain. Those inverter changes have been recent modifications to design and topology. We want to see how they act in the field for a couple of years. Eventually, there will be a shift in the methodology for evaluating forecasted expenses. We're not quite there yet, but I think we're going to get there.

JM: With that in mind, what's the average cost per KW today for a solar farm compared to 5 to 7 years ago?

CG: Five to 7 years ago, we were seeing everything from the $4,000 to $7,000 per KWDC. It's important to note that it is in DC capacity. The DC to AC ratio 4 or 5 years ago was 1.0. The modules were so expensive, everything was so expensive, developers did not want to overbuild a solar plant. Today, we're seeing somewhere between $1,300 to $2,500 per KWDC, depending on the geographic location, and on the overbuild. An average DC to AC overbuild today is about 1.3. You're going to have 30 percent more DC capacity than what the inverters are going to convert to AC electric energy. We see overbuilds anywhere from 1.2 to 1.45.

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JM: Where do you see room for improving cost-cutting measures and efficiency over the next 5 years in solar technology?

CG: I think the big cost-cutting measure will be going from 1,000 volt architecture to 1,500 volt architecture. You're going to see bigger inverters, especially for utility-scale solar plants. Furthermore, the delivery of modules to the project site will improve. Some module manufacturers are delivering modules that are already three-landscape or three-portrait so it's much easier to install them onto a tracker system or a fixed-tilt system. Versus today where you get a single module and you have to build those up on a table or an array. Those are some of the things that are going to introduce large cost-cutting measures. If you're talking about long-term levalized costs, we're definitely seeing a movement to trackers. Tracker systems provide greater electric energy output, so the net capacity factor increases.

JM: A lot of utility-scale projects are utilizing Chinese-manufactured panels. As a U.S. developer of these projects, how do they ensure quality control? Assuming one or more of these manufacturers goes insolvent, what can a project owner do to mitigate this risk? Are these panels easily swapped out or, are these any other strategies to help mitigate this risk?

CG: To start with, one of the things we do is make sure that there is a minimum level of industry-standard testing. You have your UL certification and your IEC certification. Beyond that, we look for any kind of third-party bankability report that has audited the bill of materials, and the procurement arrangements and due diligence that the Chinese manufacturer employs in order to ensure a quality module. There are a growing number of providers who will, as a third party, go into the manufacturing facility and provide commentary on the manufacturing process. Whether that is the manufacturing facility in general, or inspecting a certain percentage of modules to ensure that the bill of materials matches the manufacturing process. They will also make sure the manufacturer follows prescribed quality assurance/quality control (QA/QC) procedures, and look at the constructability of the module.

> *"The inverter space is seeing some cost-cutting measures driven by larger inverters, thereby requiring fewer for any given project.*

Beyond that, if there's a real concern with modules (for example, we're involved in a job that is using modules that have been in storage for 4 years, so they're older modules), we can review third-party laboratory testing performed by others. Typically, when we do that, we're specifically looking at extended thermal cycle testing, really any kind of I-V test, to understand if there's any light induced degradation, and if it's within the normal range of what we expect.

As far as switching out the panels, the power density of the panel continues to improve. In the same site, we tend to see higher and higher wattage panels. Depending on when you need to switch out your panels, at what point in time, there may be different considerations. The short answer is we think you can swap out the panels pretty easily. If you're swapping out panels a year down the road, it can be really easy in that the power density is very similar, and the size of the panel and how you attach it to the table or the tracker is very similar. No modifications need to be made there. If you're swapping out panels 10 years from now, you may need to take into consideration changes in power density and changes in size. As an example, if you have a string of 18 modules you may want to cannibalize that string and separate those 18 modules. So, if there are some modules that need replacing, maybe you can maintain the original output and voltage with only 10 higher power density modules instead of 18. Then, when you look at retrofitting the table or how you're going to attach that module to the table or the tracker, you might have to make some slight modification but you're only doing it on a string. You're doing it on a minimum number. Again, it's very easy to swap them out. Depending on what point in time you swap them out, there may be some different considerations about what your strategy is as far as replacing modules and making sure they fit properly within your design.

> *I would say the vast majority of projects that we're involved with meet the construction schedule on time, on budget.*

JM: What is the normal construction timeframe for a typical utility-scale solar project? Where do you put solar construction on the spectrum of construction risk compared to other power generation technologies?

CG: If you compare solar to a traditional thermal plant where you have two gas turbines and a single steam turbine, the construction risk is much less for solar. The reason is: with solar you're installing hundreds if not thousands of modules that produce electricity, versus on thermal you've got your two gas turbines. If one of them drops off the truck in transport, that's an issue. Now, you're really hurting on replacing that piece of equipment and still meeting your construction timeline. If you have modules drop off the truck during transport and you're at a 1.3 overbuild, now, you still might be able to declare COD at a 1.2 overbuild. You're construction risk goes way down just because you're installing a high number of a certain item.

It also allows ramping up manpower much more quickly because you're not constrained. If you're working on a thermal plant, you can only get so many people around a gas turbine interconnecting the wiring and the piping. In modules, you can get dedicated crews to work on chunks, blocks or arrays, and you move very quickly in installing those pieces of equipment. Again, it's a very repetitive process, so it's a lower skill set as far as the type of personnel you have to employ in order to install and interconnect. The construction risk comes way down, just because you can scale so much easier in manpower loading with a solar site.

JM: Of the projects you've looked at, what percentage meet the construction schedule on time, on budget?

CG: I would say the vast majority of projects that we're involved with meet the construction schedule on time, on budget. For the ones that don't, it's usually a permitting issue. Like we talked about earlier, when we started looking at how many months do you have between substantial completion and sunset date. We've seen delays when a permit doesn't get pulled in a timely manner, which causes a delay. But other than that, the vast majority of solar projects get built on time, on budget.

JM: What are the most common O&M issues during the operating cycle? Also, has panel degradation been greater or less than what was modeled 5 to 7 years ago?

CG: The main operating challenge, especially if you're a new entrant to the marketplace, is that solar facilities generate mass amounts of data. There are thousands of modules, and several inverters that produce data. In addition, there are meteorological stations that measure the project's irradiance values. The real challenge for most operators is in evaluating this data in a way that properly benchmarks performance. We've been involved in a number of operating facilities where the issue has been evaluating performance after correcting for irradiance and find that there's a shortfall. The owner didn't even know it because they weren't benchmarking operations correctly. There's so much data, and understanding how to digest that data and properly evaluate it and then take action if there's a shortfall in performance can be a challenge.

JM: What is considered to be the market standard for the average useful life of a solar plant?

CG: Most IEs fully believe the project will achieve a life beyond 25 years, to the extent that it was designed properly upfront and that you replace some inverters after 25 years. You're going to have to take a hit on electric energy production or replace panels if you want to maintain electric energy. But, useful life is typically 25 years.

JM: Are you seeing any longer-dated PPAs? The longest ones we're seeing range between 18 to 25 years. Have you seen anything beyond that?

CG: Nope, nothing beyond that.

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JM: Where are you seeing average capacity factors for soundly operated solar plants across various regions?

CG: The highest capacity factors that we're seeing are in the desert southwest and California. Those are getting up to 34-35 percent. But, if you go to the East Coast, you're looking at 28 percent. If you head up the coastline where snowfall is more of a factor, you're going to be closer to 24-25 percent. It's going to vary by region, the quality of the resource, as well as any availability issues. Once you start getting into areas that have high snowfall in the winter months, capacity factors will be reduced accordingly.

JM: Do you see projects compensate with additional liquidity in those regions with more variability in the capacity factor?

CG: In those regions such as Canada, there is a hit to electric energy production in the winter. Not just because of the quality of the resource, but there have been times in January or February you may only be generating half of the month because of snow. We don't necessarily see additional liquidity. We see it structured based on the minimum payments that are made. That could all change depending on how rich your contract rate is. When we start working in the Northeast, it's the fluctuation in the quarterly or six-month average revenue that's going to vary and that has to be considered when you start that service and how you make the payments. ■

CATHY GROVER *is Senior Vice President of Luminate LLC Management Consultants. She has over 20 years of experience serving the energy industry, including power, renewable energy, and oil and gas, with extensive experience in managing and leading independent engineering reviews in support of the financing of a wide range of power and energy projects. She leads Luminate's solar practice, is an authority in the resource assessment and independent engineering review of utility-scale and DG solar power projects, and has co-authored several articles and books, and presented and trained others on the subject. She has managed the solar resource assessment and independent engineering reviews of numerous solar PV and thermal projects, including the monitoring of construction and completion of such facilities. In addition to technical due diligence and independent engineering in support of financing, M&A, and emerging technologies, construction, commissioning and operations monitoring, and economic evaluations, her background includes profit center management of combustion equipment, and research and development of combustion based technologies.*

Prior to joining Luminate, Ms. Grover held consulting positions with other firms including Jacobs Engineering, Pearl Development Company, ADA Technologies, and KOCH / John Zink. Ms. Grover holds a Bachelor of Science in Chemical Engineering from the University of Tulsa, where she graduated with honors.

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INTERVIEW 6:

Legal Counsel's Role in Developing a PPA

Matt Brill and Justin Merkowitz of CoBank talk to **MARVIN ROGERS**, Partner at McGuireWoods LLP

When developing a PPA, it is critically important for both developers and off-takers to engage with legal counsel early and often. The opinions offered by legal counsel, whether in-house or external, provide all counterparties comfort that what has been negotiated and put in place in a PPA not only works, but is also enforceable.

Matt Brill and Justin Merkowitz with CoBank sat down with Marvin Rogers from McGuireWoods LLP to discuss the key role that legal counsel plays in the successful development of power project finance deals.

Matt Brill: Marvin, what are the key documentation requirements for entering into an off-take agreement with a developer or independent power producer?

Marvin Rogers: It is part of a process but the principal documentation requirement is a Power Purchase Agreement (PPA). The way you get to a final PPA can vary, depending on the size of the transaction, the type of off-taker you have, and the circumstances surrounding how badly the off-taker wants a particular project versus another. A lot is driven by what position the PPA off-taker is in and what its needs are.

If it's a small project and one that is a qualifying facility (QF) under PURPA [the Public Utilities Regulatory Policies Act of 1978], many states have standard PPAs that have been approved by the appropriate state commission. There is little flexibility around negotiating the terms in these standard PPAs. For larger projects or non-PURPA contracts, if you have a strong sponsor or there is a utility or another off-taker that wants a certain amount of renewables for whatever reason, they have a motivation to try to get the contract done. Many times the developer or a utility can announce a request for proposal (RFP) and go out with its own draft of the PPA and the parties start negotiations from there. It's a process and what course it takes depends on size and leverage, and how badly the PPA off-taker really wants to do the deal.

MB: Do state Public Utility Commission (PUC) requirements make it easier or more difficult to enter into a PPA?

MR: Yes, to both. It is a question of knowing the regulatory climate where you are considering developing a project and making sure that you proceed down a course that's consistent with the regulations in that jurisdiction. There are some states like

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North Carolina, for example, where the state tax laws and state commission policies towards QFs and renewable projects generally have been favorable for solar generation, driving strong growth in the development of solar projects relative to other states.

MB: Are all PPAs subject to a FERC ruling, or can there be times when they do not need that approval?

MR: It depends. Small QFs (20 MW or smaller) making sales pursuant to PURPA generally do not need FERC approval for PPAs. Larger QFs and non-QFs typically will obtain general market-based rate authority allowing them to make wholesale sales at negotiated rates rather than seek specific approval of the PPA. In some parts of the country, however, FERC does not have jurisdiction, such as ERCOT in Texas. But in most of the country, FERC has jurisdiction so you would need either to be exempt from those regulations or to have some sort of approval.

MB: On a related topic, can you talk a bit about the process for obtaining a large generator interconnection agreements (LGIAs)?

MR: Transmission development can be a very difficult thing. Most jurisdictions require a detailed transmission study. Obviously, financing parties care about transmission and congestion or the lack of it. Many of the interconnection facilities are based upon studies that are completed well in advance of the start date of construction for the project. Any changes to the project that impact the original study can trigger a restudy (and cause delays).

I've found that in respect of both solar and wind assets in rural areas – where many times the utility is not a large public utility, but a co-op or some other company that's been created for the purpose of acquiring transmission assets – even those transmission companies have very rigid and strict parameters within which they're willing to operate. I find that transmission counterparties have the least amount of flexibility in negotiating the interconnect agreement, as compared to some of the other project contracts.

> *"Many times the developer or a utility can announce a request for proposal (RFP) and go out with its own draft of the PPA and the parties start negotiations from there.*

The interconnection process is typically governed by standard procedures and forms of interconnection agreements. The procedures and agreements can be state or federal depending on whether the interconnection project is selling directly to a utility off-taker or into the grid. In either case, the process from initial request to final interconnection can be very lengthy. It is vitally important for developers to start the process early. Any changes to the project that impact the original study can trigger a restudy (and cause delays). There is little if any flexibility to negotiate the terms of the approved form agreements.

Justin Merkowitz: In project development, what party usually bears the financial burden of a substation upgrade or transmission upgrade?

MR: In many cases, it's a fact-and-circumstances thing. The experience I've had is that most substation upgrades are going to have to be funded by the developer. However, if the upgrade is something that the utility is going to have to do anyway, whether or not this particular project comes online, the utility might take on the financial burden of the upgrade.

MB: Does having a physical interconnection with access rights provide assurance to the developer that power from the project can be delivered?

MR: It doesn't address congestion, but it ensures that the project is provided access to the grid and that it is connected to the grid. However, the financial impact from curtailment, which can be triggered by high congestion, is typically addressed through specific provisions within the power purchase agreement.

MB: In terms of an off-taker's role in project development, do you see an off-taker having a broader interest in other key project documents that are more on the project development side with a particular project financing, or are they only concerned about the delivery of their power and the power purchase agreement?

MR: It's more the latter than the former. They typically set their PPAs up so that they don't have obligations under them until the power is being delivered in the manner and in the amounts that are required pursuant to the PPA. The conditions for satisfying that point in time are drafted into the PPA, so the off-taker becomes fairly comfortable that the developer can deliver the power in the manner that they've agreed. However, I will note that many off-takers at the beginning of discussions will have some view as to whether a particular developer is sophisticated enough to be able to complete a project. If they need 100 MWs of renewable power and they're talking to developers who control 400 MWs, then they can pick and choose a developer that they think has the best chance of success. This in some cases will depend on the level of sophistication of the developer, but also what type of financing and other contracts that developer has lined up.

MB: In a situation where the utility has put a project out for bid, does that change the utility's involvement in contract negotiations?

MR: If you're in a bid situation where the utility has put the project out for bid and they are trying to select from four or five different developers, in those circumstances, the other project documents may very well be something that the off-taker is going to care about because they're going to pick somebody that's bringing the whole package of rights to the table.

MB: So it sounds like a utility will have an interest in working with sponsors who are experienced, just as we do as lenders.

MR: Sure. In addition, the utility will want to be sure their construction counterparties are creditworthy, known in the industry, and that the technology is proven – the same things a lender would be interested in.

MB: Can you describe what a tri-party consent is in relation to a PPA and other material project agreements. Why is that so important to the three parties who might enter that agreement?

MR: It goes back to the underlying concept of a project finance, which is financing only the cash flow of a particular project without a balance sheet standing behind the debt. While you can foreclose on assets and try to liquidate those assets, often a liquidation of assets scenario isn't going to make a project lender whole. The project lender's best source of recovery of all or most of its loan proceeds in a project that hasn't gone well is to be able to take the project as a going concern and then to sell it as such. As a result, you need to make sure that the project contracts that comprise the project will follow a lender's decision to exercise remedies.

The third-party consent serves a number of purposes. The third-party vendor – be it an off-take contractor, an EPC contractor, an interconnect counterparty, an energy management agreement, or whatever the third-party contract might be – must acknowledge that the lender's security interests are being granted and can be exercised. They give the lenders notice and opportunity to cure a default. If a bankruptcy occurs and the project contract is set aside, the project counterparty will agree to give an identical contract to the foreclosing lender. They agree to make all payments into a specific account that is a controlled account where the lender is perfected in cash. The third-party consent gives a direct contractual relationship between the lender and the off-taker. It gives the lender going into the transaction some comfort that they have the ability to foreclose and take a project as a going concern and all of the contracts will still be there.

MB: Borrowers are often surprised at how arduous the documentation process is in a project financing. Can you talk about your view on that?

MR: It is a tradeoff. The borrower incurs debt to build a project, and the developer doesn't have to guarantee the debt or expose its other assets to the risk of the project. The quid pro quo for that, to get that kind of treatment, is that the lender needs to make sure that it can take the project as a going concern and that the numbers that

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populate the financial model upon which the transaction is closed, both from a revenue standpoint and an expense standpoint, are valid. In addition, you're looking to documentation to the extent possible, to minimize risk to the project and its lenders.

In order to accomplish all of those things, the documentation is very detailed and is negotiated heavily by all parties. In a typical balance sheet transaction, generally lenders do not pay as much attention to the details of the borrower's day-to-day business operations and contractual agreements. A lot of times, lenders hardly review the company's underlying contracts because they're simply financing a balance sheet. But in a project transaction, it's much different. There's a lot more detail and there's a lot more documentation required to make sure that the model reflects the details of the project contracts.

MB: When you look at project financing, should the size of the project matter? Are there other things an off-taker should consider with a small-sized project?

MR: The unfortunate thing is that, unless you're dealing with an unusual situation, the cost for doing a small transaction versus a large transaction, in many circumstances, can be quite similar. From an off-take legal counsel's perspective, the concern is to make sure that the off-taker doesn't have economic or other obligations or liabilities to a project until the project has demonstrated clearly that it can produce the power in the amounts and in the quantities that have been agreed.

MB: Do you typically see off-takers taking development risk with respect to projects?

MR: The off-taker typically won't do that. It would have to be an unusual circumstance.

MB: How should an off-taker look at the sizing of PPA security relative to their purchase requirements?

MR: If there's a default for some given period of time – I would think that a utility would not be too tolerant of lengthy defaults – the utility would consider what the out-of-pocket costs are to cover and get the same amount of power from someplace else.

> *That outside counsel sees lots of different things from different clients and they have perspectives on the market that in-house counsel may want to hear.*

MB: Should a utility consider utilizing outside experienced project finance counsel when acting as the off-taker and/or transmission provider in this type of a project?

MR: As a general matter, when a utility is acting only as a transmission provider, I don't see them often going to outside counsel because they have the in-house capability from a legal and an engineering standpoint.

As an off-taker, it does depend. Utilities are different, just like companies are different, and it depends on what expertise they have in-house. I've seen some sponsors and some off-takers with legal departments that are every bit as good as outside legal counsel. Most of the time, I see off-takers using outside counsel for PPAs.

There are benefits to hiring outside counsel, whether you have the in-house capability or not. It largely depends on the amount of time available to the in-house lawyers to focus on a project finance deal. These projects are very time-intensive, and it takes a lot of time and effort to read all the contracts carefully and then understand how they work together with all the other contracts. Another reason to think about outside counsel is that outside counsel sees lots of different things from different clients and they have perspectives on the market that in-house counsel may want to hear.

MB: If a utility seeks outside counsel, what are some of the things that you would look for in a typical project finance counsel?

MR: These are not the sort of transactions that you can take to a lawyer who has not done this type of work before and hand them a project deal and expect that they're going to get it done quickly and efficiently. Any smart lawyer can get up the learning curve – it's not

rocket science – but you're probably looking for a law firm that has done it before, knows what the issues are, and has the ability not only to identify issues but also to develop solutions. Utilities benefit from outside counsel that is committed to the industry and has done a number of transactions for different parties in the industry. Having those perspectives allows them to develop thoughts and ideas about how to propose solutions to different and unexpected problems.

MB: In our experience, we find it very beneficial when a participant has engaged project finance counsel very early in their development process. What is your opinion on the optimal timeframe for a developer to engage project counsel?

MR: A developer is concerned about cost, so they're going to try to put off hiring outside counsel as long as they can. In my opinion, they should engage knowledgeable project counsel as soon as they can and ultimately, I think, costs will be lower. There are a lot of issues that come up with land assembly, environmental analysis and permitting that many developers try to do themselves. A developer runs the risk of getting pretty far down the road with negotiations on a contract or a series of land assemblages, only to have lawyers look at them later and find out that there's an issue that has to be resolved. Having to go back to landowners multiple times or having to have permits reissued, for example, ends up taking more time and money than it should. If I was advising a developer, I would advise them to engage their engineers and counsel as early as they can.

MB: Are there any other specific things a sponsor or lender can do to reduce the time to close a project financing, other than just engaging a project finance counsel early?

MR: Sponsors and lenders must have a really clear understanding of the basic project timeline and be very organized about how they proceed. Engaging with knowledgeable engineers and counsel to help them get through the process is the best thing that they can do. Transmission studies and the permitting processes can take months, the real estate assemblage can take a long time, and many times environmental studies require a sizeable lead-time – to name a few examples.

MB: You mentioned the permitting process and some of the challenges. What are some common pitfalls associated with permitting that could delay a renewable energy project?

MR: There are many depending on what kind of project it is. For example, wind farms must secure FAA permits that govern the location and the height of wind towers. It is critical to understand what type of properties are located adjacent to a project – for example, a military base or a wildlife sanctuary. If development of a project makes significant progress, and then there are changes to the project, the developer may have to go back and get permits reissued. Sometimes, those permits have a finite life. Once you obtain them, the project needs to reach a certain point to ensure the project can be completed before the permits expire. That's why it's important not only to secure counsel early on, but also to involve quality engineers and other experts that understand the permitting process very well.

MB: Two areas where we've seen challenges are NIMBY lawsuits, as well as cultural studies that result in unforeseen delays.

MR: Yes, they can. Those are all part of the environmental studies and may or may not require a permit. You're right, those challenges can bring a project to a screeching halt if they're not handled correctly.

MB: I would like to discuss current renewable energy financing structures. Do you think tax equity and back leverage complicate the negotiation process or legal process for closing project finance transactions?

MR: Tax equity and back leverage are complicated transactions. When you have tax equity at the table, or you have lenders lending money up the capital structure, there is a larger group of parties that have legitimate points of view about the structure of a particular project. Depending on whether it's a PTC deal or an ITC deal, you may have significant arguments about how quickly lenders can exercise their remedies and how long

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they have to forebear without creating adverse tax consequences to the tax equity investors. Having those parties at the table makes a project more complicated rather less complicated.

MB: Do you think there will be a renewal of wind and solar tax benefits once they reach their expiration?

MR: That's the $64,000 question, but I have a hunch that we're probably not going to see these kinds of tax credits extended. The solar and the wind industries are becoming more and more mature. Given the current political climate, continuing to ask for federal tax dollars and state tax dollars to support these industries is going to be more and more difficult.

MB: If that holds true and the benefits of tax attributes start to go away and the benefits of projects start to go away, do you see the structure of a project returning back to more of a standard operating company type of financing versus back leverage?

MR: It could continue. The industry is forever changing and once it goes down a certain path it hardly ever goes back to exactly the way it was. You don't know what kind of developments are going to occur in the future that may take you in one direction or another. I would anticipate that there are going to be other developments that take the industry in directions that we may or may not be able to foresee today.

MB: Generally speaking, what are the most important characteristics of a financeable project?

MR: Having good, solid contracts with creditworthy parties is a really big one. Almost all financing parties are looking for strong credit ratings in their off-takers, their EPC providers, O&M providers, and the companies that are providing warranty agreements. It is critical to have rational, reasonable, tight project contracts that clearly stipulate what each counterparty can and cannot do, and what they are and are not obligated to do. Parties must be able to document the transaction with as few risks to the project as possible by contracting them away to other parties. Those are all very important to a project.

"It is critical to have rational, reasonable, tight project contracts that clearly stipulate what each counterparty can and cannot do, and what they are and are not obligated to do.

MB: To wrap up, what is the value of a legal opinion in a project finance transaction?

MR: I would say that they're very important. I've never viewed a law firm's legal opinion as that firm's guarantee of success of one thing or the other. But no reputable law firm is going to put an opinion on its letterhead unless they've looked at the matter very carefully and believe their opinion to be correct (forcing, in some cases, disclosure of facts that may not be known to the lenders or their counsel).

The benefit that you get out of having the developer's or sponsor's counsel provide opinions is the fact that some very smart, knowledgeable people – people that understand the industry and understand projects – have looked carefully at the matter, and are willing to say, on their letterhead, what their opinion is. It gives lenders and tax equity investors comfort that what has been negotiated and put in place works and is enforceable. ■

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INTERVIEW 7:

The Advancements that are Driving Down the Cost of Wind Energy

CoBank's Taylor Gunn talks to **CHRIS SCHMITT**, who at the time of this interview was Technology Manager for GE Wind. He is now the Senior Director of Renewable Asset Optimization for NextEra/ WindLogics.

Improvements to wind technology will continue to drive down project costs and increase the competitiveness of wind energy relative to other forms of power generation.

In this interview, Taylor Gunn, Lead Economist in CoBank's Knowledge Exchange Division, met with Chris Schmitt, formerly with GE Wind, who shared his perspective on the future of wind energy and the innovations that are likely to contribute the most to reducing the lifetime operating costs for wind assets.

Taylor Gunn: Chris, please provide us a background of yourself and of GE Wind.

Chis Schmitt: I've been working in wind for the last decade. Prior to that, I spent time working in thermal power, hydro and solar power, and I also have extended experience prior to that in oil and gas dynamic compression equipment.

GE Wind was formed after the acquisition of Alstom Power. Previously, GE had only modest experience in offshore wind, and it had divested its hydro assets several years prior to the Alstom acquisition. Those are new industries to come back into our portfolio.

In 2015, these companies were combined into GE Renewable Energy which is what we call a tier-one business within the GE corporate structure. It represents about $9 billion in total revenues as an aggregate business, with approximately 13,000 people operating in over 40 countries. GE Wind has about 30,000 wind turbines installed between the GE fleet and the Alstom fleet, with total installed capacity north of 48 GW, at this point in time.

We have machines in about 25 countries today, and we have over 880 million hours of operating experience. This means that we add about 1 million operating hours to that total every day. We have manufacturing facilities in the U.S., Germany, India, Brazil, and China.

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TG: How has average nameplate capacity grown over the last 5 years for on-land turbines in the U.S?

CS: If you look back just a few years ago, the average nameplate capacity of an individual turbine was less than 2 megawatts (MW), probably around 1.5 to 1.6 MW. This year, average installations will go above 2 MW. Our current product portfolio for onshore 60 Hz machines is our most popular machine, which is a 2 MW class machine with 116 meter rotor. That product is available in a range from 2.0 to 2.5 MW.

The trend in megawatts per turbine is going up. We see that growth in terms of the total market in North America, something to the tune of 6 GW to 8 GW, and out of that total amount, maybe 1GW is in the 3MW and higher-rated machines. You have the majority being sold in the 2MW class, and a substantial but much lesser quantity being sold as 3MW class machines. That is pretty consistent across all tier-one suppliers – GE, Vestas, Siemens, Gamesa, and Enercon.

TG: Today there are 2-3 MW units being sold. What do you think average turbine capacities will look like in five years?

CS: I think it's a function of where the projects are located. We traditionally think about projects which are land-constrained and projects which are megawatt-constrained. A land-constrained project usually has a limited number of wind turbines that you can put up. Those tend towards larger nameplate capacities. If you have a project with 9 pad locations, maximum, on a ridge line in a place like Massachusetts, then the bigger machine is going to predominate in terms of economics. For a place like the Panhandle of Texas or Oklahoma or Kansas where you have a lot of land and it's not too expensive, more machines of smaller nameplate produce a higher capacity factor.

The majority of projects today in the U.S. are megawatt-constrained not land-constrained, except for some areas in the Northeast or Northwest, where they are much more like a European model that is driven by land-constraints.

> *"The majority of projects today in the U.S. are megawatt-constrained not land-constrained.*

TG: Thinking about the technology that drives advances in wind energy – the rotor, blades, and gearbox – which of these components will experience the greatest innovation?

CS: You look back and your basic power equation for a wind turbine tells you that your power is proportional to the cube of wind velocity. The power is directly proportioned to the area of the rotor, which is the square of the blade length. To get more energy out of the machine, you don't have a lot of ways to change the wind resource per se, except by raising your hub height. The way you get more rotor area is a longer blade. We've put a lot of focus on blade technology as well as going to taller towers. At the same time, because you have a larger rotor, it needs to spin a little slower, meaning the torque in the drive train is increased. That means you have to start paying attention to your gear. This is a system-level solution. The rotor cannot grow faster than the gear technology can grow. Or, turbines can't go taller than the control system can modify the operation of the machine to make sure that nothing falls over. It truly has to be a system-level solution.

There have been advances in blade construction and blade materials. Certainly, the pitch system that we use today is very different than the one we used a decade ago. It's much more reliable, and it has a much greater blade response capacity. The gearboxes have evolved – I won't get too detailed on the gear design – but, in the past you had a 3-stage gearbox that had a planetary stage, and then, two horizontal offsets or standard spur gear arrangements. In the very high-torque gearboxes, especially in the 3MW product, you are now into a gearbox that's 3-stage, but it's dual planetary and one offset. Some gear ratios today are 150:1. There's been a huge advance in gear technology. It all follows the system approach because it makes no sense to put more money into a more capable gear if you don't have the rotor for it and, vice versa.

> *There are projects that in the past were deemed marginal at best, where today's technology in terms of a hub height or rotor diameter suddenly makes those projects pencil out for owners.*

TG: There are bigger rotors, bigger blades, higher hub heights. All the while, costs continue to come down. What's driving this decline from a manufacturer's perspective?

CS: As a supplier, it all starts with the levelized cost of electricity (LCOE). That is the all-in project costs rolled back into a net present value in terms of cents per kilowatt hour or dollars per megawatt hour. If you look at what's happened to the trend, it's decreased by approximately 60 percent. Today, our LCOE level is running at about 4.5 cents per KWh. A few years ago, it was 8-9 cents per KWh. Our goal is to continue to drive that down. That doesn't necessarily mean our components are going to cost all that much less, but they'll produce more energy, and thus more revenue, and that helps that side of the equation.

It's a balancing act between trying to get the most economical machines, as well as those that produce more energy at the same time. Those are two complementary things in terms of helping to drive down the levelized cost of electricity.

TG: What is the average capacity factor for on-land wind turbines being installed today in the U.S.?

CS: It's project-specific. Most capacity factors on the projects that I've seen are in the mid-to-high 40 percent. Some are as high as 50 percent. There are a few extraordinary projects where you can get a capacity factor above 50 percent, but those are a bit of a special case. Some of GE Wind's legacy projects are in the 30 percent range, and those have struggled to make their pro forma expectations over time. Quite frankly, that is one of the drivers for us is to look at our customers' success in their projects and learn from them and continue to evolve our designs.

TG: What is the thought process from GE's perspective of increasing the capacity factors of its wind turbines?

CS: That's a complicated question because not everybody necessarily looks at the capacity factor as a standalone measurement. When we talk to customers, they're talking about levelized cost of electricity, they're talking about project IRR, they're talking about project NPV, and some are even very CAPEX sensitive. It's a financially-driven discussion that goes back to fundamentally talking about what happens to prices over time and to the LCOE over time. The capacity factor, in and of itself, is something that for us was front and center as a huge focus a few years ago. It's still very important, but each project is somewhat unique in terms of its wind resources, and its leveraged capital structure. Ultimately, it'll have to pencil out in the pro forma. While the capacity factor is important, we can also offer multiple hub heights, multiple rotor diameters for a project, even multiple models, depending on the customer's goals.

TG: How have advancements in turbine technology changed the feasibility of locating wind in certain locations that did not pencil out in the past?

CS: I think you're right on. There are projects that in the past were deemed marginal at best, where today's technology in terms of a hub height or rotor diameter suddenly makes those projects pencil out for owners. There is a greater interest in areas that you would call class 3-type wind machines. There are some regions in the world that are looking at class 4-type wind machines that we're exploring. You get a bigger rotor, your loads increase, and even in an area with lesser wind speeds, you still have a large force on the machine to deal with, from a physics perspective.

For instance, we recently closed a project in the Far East that has a hub height above 150 meters, with a large-

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rotor-diameter machine. Right now, that would be above the FAA tip height limit in the U.S. of 500 feet. (Speaking of that, there are more and more permit applications with FAA to go taller than 500 feet.) To me, this trend is an indication of investors in the U.S. seeking higher returns from lower-wind resource projects.

TG: How have operations and maintenance improved for wind turbines in the last five years?

CS: I'd answer that along the lines that we see a greater and greater alignment between owners and original equipment suppliers. I would say there are more and more customer-service agreements or long-term service arrangements where the interests of the parties are becoming aligned. In other words, the OEM is not just there to provide equipment, but rather to be there long-term with the customer, oftentimes through the project financing flip of 10 years, sometimes 15 years. It depends on the particular deal. In the past, warranty plus a year or two was typical, and then the parties would renegotiate. There are customers that do self-provided maintenance. That's a whole different subject from the maintenance agreement.

GE has invested in a very large testing and simulation facility in our Greenville, South Carolina, plant, where we have focused on working on up-tower repairs, not requiring a crane. You're talking about hundreds of thousands of dollars any time a crane shows up to maintain a machine, before you even begin any repair work. One of the big focus areas in research that we've done over the past five years is how to do as much of the repair work up-tower and eliminate the crane.

In terms of the gearbox, GE machines isolate the wear items in the gearbox, such that they are serviceable up-tower. We have specifically designed gearboxes to be serviced up-tower, whereas five or ten years ago you'd have to completely pull out a gearbox – but that's no longer necessary.

In terms of rotor blades, lightning strikes are the most common source of damage. A few years ago, the only way to replace rotor blades was to bring in a big, heavy crane that could get up to the hub height of the turbine

"In terms of rotor blades, lightning strikes are the most common source of damage.

and drop the rotor down. That is typically a 50-to-60 ton load that has to be lowered to the ground, requiring a substantial crane. We have developed blade exchange technology that can use two very much smaller cranes, at half the cost, to replace a blade if it's hit by lightning.

Other improvements include the type of greases that GE recommends to use in certain bearing types. GE has done extensive wear testing on greases which, while it sounds mundane, the wind turbine is living on this stuff so it has to be good. We've also improved the gear oil itself and changed our recommendations. We're advancing all of these things at the same time which ultimately reduces the operation cost to the owner.

TG: Where's the most innovation occurring for wind turbine operations and maintenance?

CS: I might surprise you with this answer, but I'm going to shift away from hardware-specific or component things and talk about data analytics. We have a remote monitoring center, and many of our customers choose to remain connected with us after the warranty period. When we provide a wind turbine, we want to watch its performance and understand how it's running beyond the warranty period, what fault codes it's sending, and the history of resetting those to keep the turbines online, etcetera. Some customers choose to do that themselves after the warranty period. Some have recognized the value in our data analytics.

The remote operation center which is based in Schenectady, New York, is a 24/7 facility where each operator is responsible for several hundred megawatts of machines. They're trained in knowing how the fault codes are derived and what they mean. They're looking at weather patterns in real time. For example, machines could shut down because there is a thunderstorm. Operators will not restart the machine until the thunderstorm passes.

For me, it's the data analytics. How are the accelerometer readings on the gearbox trending with what other gearboxes report over time? Is that gearbox good or is it something that we need to look at? How is the machine power production looking based on real time SCADA data? You can look at a wind farm and see that an individual machine is under producing. Why is that? Maybe the control codes were set the last time somebody visited the turbine and they weren't reset back to full, or maybe there's some curtailment being put on that turbine by the grid operator. Ultimately, customers only make money when the wind is blowing and the machines are turning. That's what the O&M equation is all about, being sure that those machines are available.

TG: What about older wind farms that GE has been a part of. Do you go in and retrofit some of those units so you can apply some of your data analytic capabilities?

CS: GE has a very large legacy fleet, making this is a very interesting subject. The fleet has evolved over time in terms of its control capabilities. Today's machines can be commanded to do things that machines produced a decade ago cannot do. GE offers a range of service offerings for older machines that enhance their value to the customers. This includes everything from increasing the nameplate capacity to increasing the firm capacity by operational schemes.

GE can add some operational features that allow the turbines to deal better with icing, which in some projects entails a significant loss of energy. As GE learns more about advancing state-of-the-art technology in the new machine category, we try to carry it back into the existing services fleet, and vice-versa. Sometimes we address service solutions that could help improve the new unit side. When you look at wind turbine operations, one of the potential loss factors is what we call high-wind speed hysteresis. This can occur on a site that's very windy where you could exceed the rated wind speed of the machine. The machine wants to shut down at that point. But instead of shutting down, maybe the machine shifts to lower power, allowing it to ride through the higher winds and maintain production. That way, you don't have to go through an entire shutdown and restart sequence. It provides anywhere from 30 to 60 minutes of extra generating time at rated power. Those things add up a lot over the wind farm, and over the years. There are many improvements that can be made to older wind farms.

More innovative service offerings include options such as repowering. Because of the new provisions that have been clarified under the production tax credit (PTC), a customer can repower a site by putting a larger machine head and a larger rotor on the existing tower and machine infrastructure. We're working very closely with some customers who are pursuing repowering opportunities. This can range from something as simple as a complete new machine head and rotor on an existing tower, to reusing some of the older components – for example, a new gearbox, or putting on a new hub and rotor system – while using existing wind farm infrastructure. That provides the customer an opportunity to reset under PTC and maintain their existing PPA. It's a very favorable equation for some customers.

TG: Does it provide a lower levelized cost of energy?

CS: Yes, and it goes back to your question about capacity factors. Repowering can take a capacity factor in the mid 30's and kick it up into the 40's. In terms of financial return, that's very, very attractive. I'd say other unique service opportunities that have been requested by customers include retrofitting machines from OEM's that have gone out of business with more current GE technology. In addition, on a selective basis, GE has looked at what we call universal fleet services, which is non-GE equipment service. It's on a very selective-type basis.

TG: Can you talk about some of the tools that GE uses for resource assessments, and how the variability of wind resources influences the design of GE wind turbines?

CS: There are commercially available wind resource assessment calculations programs. You want to start with at least a year of data that's been gathered at a particular site. The more years of data you have, the better.

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> *When you look at wind resources, there are three big topics – the wind average velocity, the density, and the turbulence.*

One particular site in Canada comes to mind where a customer had gathered data for 13 years. It was pretty irrefutable as a data set. I don't want to endorse one program over another. We tend to use a program called Wind Pro. There's also Wind Farmer. There are various other programs also available.

The independent engineers have developed their own programs and their own methodology. I would say that any methodology that uses a long-term data set adjustment is going to result in a more reliable wind resource assessment. In other words, you have a year or two or three of data and you adjust that using a 30-year data set of wind, which is not necessarily at that site but you can translate from that site to adjacent areas where measurements were taken. The mesoscale approach to wind has produced a more reliable wind resource. American Wind Energy Association (AWEA) completed a study a few years ago, and this technique seemed to dominate the competition in terms of methodology.

The wind resource assessment that we do at GE can vary from a very simple condition where the customer gives us a summary to one where we do a complete wind resource assessment on our own. The greatest variation that a customer has – the greatest risk is – what is the wind resource? It's always a question of the length of data that you have, the quality of data that you have. Did you use calibrated equipment to gather your data? Was that equipment consistent through the collection period, or did you change something along the way (which means that you then have a completely different set of variables you're working with)? . Every project needs very careful scrutiny in terms of what the wind resource is thought to be.

In addition, there's a natural phenomenon called inter-annual variation that occurs with wind. It means that you have "windy" years, and you have "not windy" years. It's on a cycle. You need to know where you are in the inter-annual variation cycle in terms of where you measured your wind. There was a famous wind study that was done several years ago in Brazil. It happened that the three years of data they took were at the very peak of the inter-annual cycle. That project never penciled out because that "windy" wind never showed up again. You have to be careful on wind assessments. That's one of the fundamental underpinnings of this industry.

When GE looks at that, we have to interpret the wind data in terms of how it impacts the turbine. Not just the power output, but also the physics of the wind operating on the turbine. For example, the wind force placed on one of our 2 MW-class machines is approximately equal to a large commercial jet engine at the hub height; there is 80,000 to 90,000 pounds of thrust operating through that hub. It's a tremendous amount of force. If the customer's wind resource or if the wind resource data are inaccurate, it can have a big impact on loads. Loads impact your availability, and if your machines are not available, power is not being generated when the wind is blowing. That's how we look at it. We want to be sure that the wind resource is appropriate to the machine type that we're offering.

When you look at wind resources, there are three big topics – the wind average velocity, the density, and the turbulence. People tend to focus on the velocity of the wind. If I have high-wind velocity in Colorado and high-wind velocity in Texas, that's two very different energy equations because the density in Colorado is so much lower because of the high altitude than it is in Texas.

Turbulence is a big deal. Turbulence is the tumbling of the wind through the air, instead of a smooth laminar flow. That produces loads that go sideways on the turbine instead of directly on the turbine. The turbulence in the air is very important as a loads consideration for siting the turbine.

TG: Is GE involved in the development process early on to influence the siting of project?

CS: This is very much customer-specific and project-specific. We deal with some customers who are going to site turbines on one out of every 10 sites that they're developing. We work with other customers who say, I have two sites and I want to develop one of these two, which is a completely different dynamic in terms of how much effort you have to put forward to do a siting analysis. Sometimes the customers come to us with a wind farm completely laid out, already pre-sited and ask us to confirm that our machines are suitable for that layout. Other customers will come to us and say, this is our site, what machine do you recommend and where do you recommend we put them?

Oftentimes, there are factors in projects such as landholder agreements. Perhaps covenants with these landowners say I'm going to put so many machines on your land. You could be facing some wildlife exclusion zones or some areas of what we call, setback areas, to occupied structures or critical infrastructure where you're prohibited from putting turbines. The whole layout of the wind turbine farm is a bit complicated but something we definitely participate with our customers on.

When I was working on a major project on the West Coast with several hundred turbines, we did an improved layout that increased the energy capture of that farm by about 2 percent, which got us the equivalent of a few turbines for free, in terms of energy. We're extremely sensitive to the wind direction. Some projects are what we call monodirectional wind. The sun comes up, the wind blows in one direction, and then the sun goes down and it's over. There are others that have through the day offshore and onshore wind flows. There are some that are very strongly one direction per season. Every site is a bit unique, and all those things go in to make sure you have an effective layout that's going to give you the most amount of energy for the number of turbines that you're putting into a farm.

CHRIS SCHMITT *is the former Technology Manager for GE Wind, and is currently Senior Director of Renewable Asset Optimization for NextEra/WindLogics. Chris's current role focuses on technology & reliability improvements for NEER/NEP power generation fleets in wind and solar, and is based at the FPL Juno Beach campus.*

Prior to joining NextEra in Florida, Chris had several roles in the Power Generation businesses at General Electric, working across power technologies for Thermal GT/ST/CC, Hydro, Solar, and Wind. These included various leadership assignments for product management, engineering, commercial sales, project engineering, and Six Sigma quality.

Before GE, Chris worked with the Dresser Rand Turbo-Products Division, focused on power generation and Oil & Gas equipment. He held several management positions in operations, engineering, sales, and projects, as well as the Regional Director of business units located in Europe.

Chris earned a BS Engineering from Cornell University, and post graduate business courses with Harvard, Kettering University, Georgia Tech, and the University of Chicago.

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ABOUT COBANK

CoBank is a cooperative bank with over $126 billion in assets serving vital industries across rural America. The bank provides loans, leases, export financing and other financial services to agribusinesses and rural power, water and communications providers in all 50 states. The bank also provides wholesale loans and other financial services to affiliated Farm Credit associations serving farmers, ranchers and other rural borrowers in 23 states around the country.

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