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Building Blocks for Distributed PV Deployment, Part 2: Interconnection and Public Policy

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Webinar Panelists

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Kala

Before we begin, I'll quickly go over some of the webinar features. For audio, you have two options. You may either listen through your computer or over your telephone.

If you choose to listen through your computer, please select the "Mic and Speakers" option in the Audio pane. Doing so will eliminate the possibility of feedback and echo. If you choose to dial in by phone, please select the "Telephone" option, and a box on the right side will display telephone number and audio PIN you should use to dial in. If anyone is having technical difficulties with the webinar, you may contact GoToWebinar's Help Desk at 888-259-3826 for assistance. If you would like to ask a question, please type it into the questions pane at any time.

The audio recording and presentations will be posted to the Solutions Center training page within a few days of the broadcast and will be added to the Solutions Center YouTube channel where you will find other informative webinars as well as video interviews with thought leaders on clean energy policy topics. Finally, one important note of mention before we begin our presentation, is that the Clean Energy Solutions Center does not endorse or recommend specific products or services. Information provided in this webinar is featured in the Solutions Center resource library as one of many best practices resources reviewed and selected by technical experts. Today's webinar agenda is centered around the presentations from our guest panelists Alexandra Aznar, Sherry Stout, and Jason Coughlin, who have joined us to discuss the building blocks four and five of establishing a distributed PV program. Before we jump into the presentations, I will provide a quick overview of the Clean Energy Solutions Center.

Then, following the panelists presentations, we will have a question and answer session where the panelists will address questions submitted by the audience. At the end of the webinar, you will be automatically prompted to fill out a brief survey as well, so thank you in advance for taking a moment to respond. The Solutions Center was launched in 2011 under the Clean Energy Ministerial. The Clean Energy Ministerial is a high level global forum to promote policies and programs that advance clean energy technology to share lessons learned and best practices, and to encourage the transition to a global clean energy economy. 24 countries and the European Commission are members, contributing 90 percent of clean energy investment and responsible for 75 percent of global greenhouse gas emissions.

This webinar is provided by the Clean Energy Solutions Center, which focuses on helping government policy makers design and adopt policies and programs that support the deployment of clean energy technologies. This is accomplished through support in crafting and implementing policies relating to energy access, no-cost expert policy assistance, and peer to peer learning and training tools, such as this webinar. The Clean Energy Solutions Center is co-sponsored by the governments of Australia, Sweden, and the United States, with in-kind support from the government of Chile. The Solutions Center provides several clean energy policy programs and services, including a team of over 60 global experts that can provide remote and in-person technical assistance to governments and government supported institutions; no-cost virtual webinar trainings on a variety of clean energy topics; partnership building with development agencies, and regional and global organizations to deliver support; an online library containing 5500 clean energy policy related publications, tools, videos, and other resources. Our primary audience is made up of energy policy makers, and analysts from governments and technology organizations in all countries, but we also strive to engage with the private sector, NGOs, and civil society.

The Solutions Center is an international initiative that works with more than 35 international partners across its suite of different programs. Several of the partners are listed above, and include research organizations like IRENA and IEA, programs like SEforALL, and regionally focused entities such as ECOWAS Center for Renewable Energy and Energy Efficiency. A marquee feature that the Solutions Center provides is a no-cost expert policy assistance known as Ask an Expert. The Ask an Expert service matches policy makers with more than 60 global experts selected as authoritative leaders on specific clean energy finance and policy topics. For example, in the area of energy efficiency, we are very pleased to have Hugo Lucas, the head of the energy department at Factor CO2, serving as one of our experts.

If you have a need for policy assistance in energy efficiency or any other clean energy sector, we encourage you to use this valuable service. Again, this assistance is provided free of charge. If you have a question for our experts, please submit it through our simple online form at

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cleanenergysolutions.org/expert. We also invite you to spread the word about this service to those in your networks and organizations. Now, I'd like to provide brief introductions for today's panelists.

First up today is Alexandra Aznar, a project leader at the National Renewable Laboratory in Golden, Colorado. She works on clean energy policies and provides solar technical assistance to local, state, and national level policy makers. Following Alexandra, we'll hear from Sherry Stout, an engineer at the National Renewable Energy Laboratory in Golden Colorado. Much of Sherry's work involves energy resilience planning at multiple jurisdictional levels. And our final speaker today is Jason Coughlin, who is a senior researcher in distributed solar project finance and development at the National Renewable Energy Laboratory in Golden, Colorado.

He focuses on solar project financing, as well as on the non-hardware cost associated with distributed PV. And with those introduction, I'd like to welcome Alexandra to the webinar.

Alexandra

Welcome to the United States agency for International Development USAID and National Renewable Energy Laboratory—NREL's—webinar series on distributed photovoltaics. My name is Alexandra Aznar, and I'm a project leader at NREL, and today, I'll be talking about building blocks for distributed PV deployment in developing countries. Please note that this is the second webinar in a two-part series on distributed PV building blocks. A recording of the first webinar can be found on the Clean Energy Solutions Center website, as well as GreeningtheGrid.org. In addition to this series, NREL supports the USAID distributed PV pilot program, the objective of which is to help USAID partner countries address barriers to safe, effective, and accelerated deployment of DPV.

This USAID pilot program is a multi-year effort that will build capacity in partner countries through pilot projects targeted to specific technical policy and regulatory needs. If you're interested in this program, please reach out to the contacts listed here for more information. That brings us to what we call the building blocks for distributed PV or DPV deployments. This schematic shows the DPV building blocks and their relationship to each other. The first building blocks is Vision, Goals, and Roles.

Policy makers, regulators, utilities, and other relevant energy stakeholders should consider what the role of DPV will be in a country or region and which institutions will be responsible for specific activity. The second building block is defining what distributed generation—or DG—is in your specific context. DPV is, after all, a specific DG technology. After that, creating the compensation mechanism for DPV is important. A compensation mechanism has three components, and that's a metering and billing arrangement, a sell rate, and a retail rate.

It also has implications for utility cost and risk allocation. The last webinar focused on these first three building blocks. The metering requirements feed into building block number four—Interconnection Processes, Standards, and

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codes that dictate how a DPV system can be connected safely, reliably, and expediently. The compensation mechanism

and interconnection processes, standards, and codes come together in a standard interconnection contract in agreement between a customer with DPV and the utility. Building block number five is Public Policy Support.

Public policies—including financing and business models—can create additional incentives and pathways for DPV deployment. In the previous webinar, we explored building blocks one through three. Today's webinar will focus on building blocks four—Interconnection—and five—Public Policy Support, with an emphasis on finance and business models. Now, I'm going to turn it over to my colleague, Sherry Stout, to discuss building block number four, Technical Interconnection.

Sherry

Thank you, Alex. Today's learning objectives on building block number four include identifying basic DVP technical challenges and major concerns of electric utilities, as well as understanding the basic interconnection processes and technical screens used for quick review and approval of DPV systems. We're going to start out by looking at today's power system. If you notice, in today's power system, energy is delivered from a centralized generation to load _____ needing high voltage power lines and distribution networks. Power generally flows in only one direction.

This is a long-standing process and a well-understood system. However, if you fast forward to tomorrow's power system, you will see that the world is much more distributed, more digital, and more decentralized. This results from a common trend—retirement of older plants, new renewables to meet policy goals, investment in energy efficiency and demand response, and low-cap cost natural gas. There are several key technology challenges that will need to be addressed with innovation to make this happen. The concern that we hear most often from utilities is that of voltage control.

We also hear concerns related to reverse power flow, protection system coordination—as when you start pushing current in different directions due to the circuit breakers might not coordinate as they were designed to—but also, we hear unintentional islanding and power flow as additional concerns. Increased equipment operations to regulate voltage—for example, switching capacitor banks—can decrease life spans of devices while also increasing maintenance needs. Significant DPV on any circuit can also cause load masking. One common question that we get—probably the most common that we get—is, "How much PV can I put on a circuit?" And the answer is, it really depends.

Factors involved in making that determination include the size and locations of the PV systems on the circuit, the local cloud variability, and the spatial diversity of the DPV system, presence of other generation and loads on the circuit, impedance of the feeder, and so on. In general, though, large systems that are distant from substations are more challenging than smaller, closed systems. It's also really important to note that technical impacts are generally easy to manage at penetrations of less than 100 percent of minimum daytime

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loads or less than 15 percent of total peak load. With that said, it's also really important to note that DPV can also be good grid citizens. And in that, I mean that in spite of these concerns, the DPV system can actually help maintain a stability of the grid.

This is largely accomplished through enacting appropriate codes, standards, and regulations for the interconnection of these DPV systems. Regulations ensure that DPV systems have appropriate voltage and frequency to match the local grid; voltage and frequency ride throughs to meet local requirements so the devices will stay online through any kind of minor grid problem; protection against unintentional islanding—in other words, they don't run when the grid is down. This incorporates safety and equipment failure issues; the ability to provide excellent power quality—and that includes harmonics and making sure the voltage is matched to the utility; system protection—making sure that the fuses along the lines and the circuit breakers at the substation are coordinated; and they also can add to synchronization, protection against some of that islanding, grounding, have disconnect devices, protective relays. There's a lot of ways that these DPV systems can actually balance the grid more than harm the grid. To do that really involves having an appropriate interconnection process.

So, the interconnection process is the general framework for DPV interconnection. Interconnection standards are put in place by appropriate authorities. These include grid interaction codes as well as construction or building requirements. Next, the interconnection process—the blue circle in the middle—provides a process to be reviewed by any proposed DPV system to ensure compliance with grid interaction standards. And finally, a permitting process is a review of compliance with the building or construction code. So, we're going to talk a little bit more about that interconnection process.

This is a graphic of this classic interconnection process, and it illustrates what some utilities have created for their own interconnection process. This is a logical approach that utilities follow no matter where they are. So, first—proposed DPV systems must complete an application process that provides all the details of the equipment and shows compliance with applicable codes and standards. The utility then reviews the application. Fast-track screens—which we'll talk about here in a minute—allow for DPV systems to quickly receive approval if they meet some additional requirements.

If these screens are failed, additional screening of the proposed DPV system will take place. If this screening is failed, various levels that impact study, then modeling will also be required as a DPV developer. This process can be really costly and very time consuming. Once the application is approved, the DPV system is installed, and then, the system will be inspected to ensure compliance with a proposed plan and will be given permission to operate—that is, permission to interact with the grid and provide power. Impact studies are part of the modeling and mitigation process for systems that fail to fast track screens and supplemental reviews, and the modeling allows you to see any issues—for example, voltage challenges—and come up with a solution to meet those challenges.

Most models are pretty much around voltage. You do see some other models as well, but primarily, modeling is done to look at voltage issues that could arise from a DPV installation. So, these are some technical screening examples. And so, screenings are—technical screens are simply a set of technical questions that help illuminate a quick path for a simple system. They're easy—mostly "Yes" or "No" questions, and they've been recommended for many utilities, both in the US and abroad.

The most widely adopted set of technical screens are those founded in the small generator interconnection procedures. And if you pass all of these screens, you can skip impact studies usually. And generally, these screens are passed if you're under 15 percent penetration on your line. This is typically very conservative screen. Some utilities are beginning to move away from this metric and look more at planning towards minimum daily load rather than 15 percent of peak load.

Another issue that arises when we start looking at the interconnection process is that of time. The more time you spend in interconnection, the more money that generally costs. And so, one NREL study recently found that the medium timeline for full PV interconnection was about 53 business days—and that's from the date that the PV installer submits the interconnection application to the utility. The application review and approval stage represents the lengthiest part of the process and that took, on average, about 18 business days. Construction represents, by far, the shortest stage in the process, taking an average of two to four business days.

Streaming the application review and final authorization process can ultimately benefit both utilities and solar customers by reducing time and cost associated with going solar. In the US, some states do regulate the time for interconnection, however, regulations do not typically ensure that PV interconnection projects actually meet that target timeline. Note the circled numbers in applications exceeding the time requirement. This NREL study found that the interconnection time requirements were exceeded anywhere from 37 to 57 percent of the time on DPV installation. However, while these timelines are difficult to enforce, they do appear to be somewhat effective in reducing the overall length of time it takes to connect the solar system to the grid.

There are some international examples as well. One example of a mandatory interconnection timeline is from Mexico. Mexico's interconnection manual for power plants below half a megawatt, developed by the Ministry of Energy in Mexico, establishes that interconnection requests must be resolved within 13 working days or fewer where no interconnection study is required, and 18 days of the study is required. So, for low voltage interconnection, requests would be automatically accepted after 18 days has passed without a response. The establishment of interconnection timelines and their transparency makes expectations on both customer and utility side clear and aids in aids in _____ of deployment of these DPV systems. Interconnecting distributed generation—or DPV onto a nation's grid—requires several things.

Those includes rules, procedures, and agreements that usually come in cooperation with a public utility commission or a utility authority. Of course, you must have proper technology for interconnecting in a safe, reliable, and cost-effective manner, and finally—and very importantly—you must have codes and standards in which to make all of the systems work together in a coordinated and safe manner. It is important to have codes and standards from the utility side, the customer side, and where the two meet—or the point of common coupling. In the US, utility side codes include the National Electric Safety Code and the Utility Manual of Safe Practices. On the customer side, the National Electric Code and UL1741 ensure safe installation and proper electric equipment standards and then finally, at the point of common coupling where the two come together, IEEE 1547 governs how DPV interacts with the electric grid.

IEEE 1547 is the interconnection standard. If you have any work in designing or maintaining distribution circuits, and of course, dealing with interconnection of DG systems, you should know this standard. This standard was developed for a 60 hertz grid; however, you can take this standard if you're looking at developing your own standard and adjust it to your local context. So, that's just the basic technology and interconnection standards for the building block number four. We've reviewed all of those building blocks for interconnection with that technical process and now, I'm going to turn it over to my colleague, Jason Coughlin, to walk you through building block number five on public policy support with a focus on finance and business models.

Jason Thank you, Sherry. So, welcome to the second and final portion of today's webinar titled Best Practices and Emerging Trends in Distributed PV Financing and Business Model. The learning objectives of this webinar are to understand both established and emerging financing options and the types of business models that both enable and promote the growth of distributed PV markets. As we discussed, we are defining distributed photovoltaics as typically behind-the-meter project, one megawatt or less, installed at the distribution level of the utility grid. As it relates to financial incentives, as a policy maker, two key questions are the goals behind offering the incentives and the source of the funding to pay for them.

Funding for incentives can come from government budgets, utilities, utility rate payers, or international funders, among others. Tax credit incentives and exemptions—tax credits reduce the overall lifetime cost of a solar project by reducing the taxes on a dollar per dollar basis that the owner of a solar project owes its government. Recovering a portion of your investment in solar as a result of paying less taxes improves your return on investment. Production based tax credits refer to tax credits that are earned for every kilowatt hour of electricity produced by the PV system. These production-based credits are more common for wind projects, and they are earned over time as electricity is produced.

Project developers can raise capital by partnering with investors who can utilize these tax credits to [Break in audio] taxable income from other activities. Investment based tax credits are calculated based on the underlying cost or investment of the solar project. These tax credits can typically range anywhere from 10 to 15 percent of the installed cost of the project, depending on the location. As with production tax credits, the developer of the solar project can raise capital by partnering with investors who can utilize the tax credit. Accelerated depreciation is a tax deduction rather than a tax credit, and it reduces the amount of income that is subject to taxation.

Finally, a whole range of tax exemptions may be available that reduce the upfront cost of installing a PV project—for example, exemptions from sales tax on purchased equipment and exemption from import taxes on imported equipment. In addition, ongoing operating expenses can be reduced as a result of exemptions from annual property taxes and other recurring tax obligations. Turning now to rebates—in addition to tax credits, additional policies can be put in place at the state, local, and utility level that provide either upfront cash incentives or production-based cash incentives. Upfront cash incentives reduce the initial cost of installing solar projects, whereas a production-based incentive provides ongoing payments to the system owner based on the system's actual kilowatt hour production. Upfront rebates are typically expressed on a per-watt basis—for example, $1.00 per watt.

The dollar value of these incentives tend to fall over time when certain installed capacity targets are reached or in parallel with declines in market cost for distributed solar projects. For example, as we'll be seeing on the following slide, the California Solar Initiative, here in the United States, launched in 2007, initially offered incentives in the range of $2.50 to $3.25 a watt for distributed PV projects. However, local incentives have now, for the most part, been eliminated in California. Performance based incentives provide the project with additional cash flow that can help repay the financing used for the installation. Solar renewable energy certificates are comparable payments for the environmental attributes produced by a PV system are a form of a production-based cash incentive, as are feed in tariffs.

Both S-Direct, as they are known, and feed in tariffs are covered in another learning module. Financial incentives can be targeted at specific sectors such as homeowners if policy makers want to develop a particular segment of the market. Alternatively, incentives for solar development on abandoned or contaminated land might be higher than comparable projects on undisturbed land. Finally, incentives can be directed at lower income households, for example, as a way to more equitably provide access to the benefits of solar energy. If incentives are to be provided, the goal should be to provide transparent incentives that decline over time as the cost of solar decreases and when market objectives are met.

Abrupt reductions in or the elimination of incentives can kill a market, whereas over subsidization can lead to unnecessary government spending and less market pressure for uncalled cost to decrease. Notice how the incentives in California stepped down over a fixed schedule as installed solar capacity

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targets were meet. Distributed PV generation business models include both customer owned projects, projects owned by third parties who can more efficiently use the available tax credit, and utility owned investments and distributed solar projects or companies. When a property owner decides to install solar on their property, there are a number of ways to pay for it. The easiest, but often the most difficult for property owners, is to pay for the PV system in cash.

Paying cash avoids the need to work with a lender and it saves on interest. However, most property owners need to finance their investment in solar and take out a loan to do so. Standard personal or home equity-based loans—which are loans based on the value of the house—can be used for solar. These loans are either secured or unsecured. Secured means that the borrower has pledged some form of collateral in order to get the loan.

In certain locations, programs may be available that offer low-interest loans for solar projects as a way to encourage the market to develop. In addition, specialized lenders also offer solar-long products with the repayment schedule of the loan tied to the performance of the system and the receipt of any incentives. Another business models that allows for direct ownership uses property tax payment as the method by which the project financing is repaid. In these cases, the project loan is secured by the value of the underlying property and can lead to lower interest rates and longer loan terms. In the US, this form of property-based financing is known as pace financing.

In all of the direct ownership scenarios, the building owner will take advantage of any available tax or other incentive to reduce the overall cost associated with the investment. Under third-party ownership business model, instead of the building owner directly buying and owning the PV system, a third-party solar developer assumes these roles. The third-party solar developer will finance, install, own, operate, and maintain the PV system, with the building owner acting as the project's hose. As the project's owner, the developer and its investment partners will use the various tax credits and incentives. The building owner allows the PV system to be built on his or her property and agrees to either purchase the electricity generated by the PV system under a power purchase agreement or lease the equipment from the developer under a solar lease agreement.

Third-party ownership models are particularly popular when the cost of solar is high and the building owner can't—or chooses not to finance the project. Often times, the tax credits are better utilized by the third-party investor rather than the building owner. An added benefit is that the operations and maintenance responsibilities fall to the third-party and not the building owner. Whether or not third-party business models are considered legal and available in a market often depend on existing utility regulations and whether or not non-utility companies can sell electricity to third parties. The contract commonly used in third-party ownership transactions is called the Power Purchase Agreement—or PPA.

A PPA is a long-term contract—commonly, up to 20 years—signed between the PV system owner and the host, in which the former agrees to generate

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electricity and the latter agreeing to purchase electricity based on some predetermined pricing methodology. Note that as illustrated in the diagram, the host remains interconnected with its local utility and continues to receive service and pay for electricity consumed from the grid. Individual consumers can also join together and conduct a group buy to lower the cost to each of the participant individual systems. These group buy programs are often organized by neighborhood or workplace. Under a group buy, a group of interested home and business owners collectively educated themselves on solar and competitively select one or more solar installers.

The competitive selection process can result in a price discount in excess of 10 percent below what any individual participant would likely be able to get on their own in the marketplace. Solar installers are able to offer these discounts because these group buy programs generate low-cost sales leads and create opportunities for economies of scale. Participants benefit from available incentives and tax credits similar to those who install solar outside of group buy programs. This is also true for policy measures such as net metering. Both customer-owned and third-party ownership business models have been incorporated into group buy solar programs.

For those that don't want to install a PV system on their property or who don't actually own property but instead rent, community solar offers an opportunity. Community solar or shared solar refers to a single larger system in which consumers each subscribe or purchase a small share of the project's output. For example, a 1-megawatt community solar project might have 1,000 subscribers, each paying for and receiving the benefits of 1 kilowatt's worth of solar generated electricity. Subscribers can make either a one-time upfront payment or make monthly payments over the life of the project. Community solar is popular in places such as the United States and Germany.

In the latter, it is often known and done through what are called energy cooperatives. A community solar project typically has a series of relationships between the various participants. In a third-party owned and developed project, subscribers will enter into separate contracts with the solar developer. The solar developer will have a contract with the utility to deliver the physical electricity, and finally, the utility will provide utility-billed credits to the subscribers who are also utility customers. In a utility developed project, the subscribers will deal with the utility and not necessarily have a contractual relationship with the solar developer.

Virtual net metering, or the ability to receive utility bill credit for a solar system not located on the customer side of the meter or property is a key policy element which enables community solar. In addition to assisting its customers with the installation and interconnection of their PV systems, utilities can also directly invest and distribute solar projects. There are many ways to do this. If allowed by regulators, utilities can simply buy and install PV systems on utility property and interconnect them directly to the grid. Alternatively, utilities can contract with their customers to lease their roofs in installed company-owned solar systems.

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In these instances, the electricity flows directly into the utility grid with the homeowners getting a monthly lease payment over a long term—such as 20 years. As noted in the discussion in the previous slide, utilities can also develop their own community solar programs. Finally, utilities can invest in solar projects to take advantage of the tax incentives. This is often accomplished through investments and projects outside of utility service territory. One of the earliest rent-a-roof models was launched in Gujarat, India in 2010 and it has spread to the other parts of the country.

Public/private partnerships attracted approximately $12 million in private financing. Two private firms each won 25-year concessions to install 2.5 megawatts of PV on the rooftops of public buildings and private residences and connect them to the grid. Up to 80 percent of the rooftops were government buildings, which reduced the risk to the developers of finding sufficient usable roof space and minimizing contracting issues. In addition to India, examples of rent-a-roof models are found in the United States as well—in Arizona with Arizona Public Service, and California with the Los Angeles Department of Water and Power. In both of these instances, the utility pays the homeowner $30.00 a month for 20 years in return for leasing their roofs so that small PV systems can be installed on them.

The electricity generated from these systems in fed directly into the electricity grid. A second roof pilot program in Arizona—this time, with Tucson Electric Power—is structured differently. Instead of a roof rental program, homeowners agree to pay a fixed dollar per kilowatt charge per month in return for the solar electricity generated by the PV system. It is similar to a solar lease program in this regard. There are a few ways in which utilities can develop their own community solar projects as previously discussed.

The utility can finance, build, and own the underlying PV system, or, it can enter into a power purchase agreement with a solar developer to buy solar electricity. In both cases, the utility can build a community solar program around the solar electricity and offer subscriptions to its customers. These subscriptions may be packaged as kilowatt hour blocks of solar generated electricity or expressed in kilowatts with customers receiving utility bill credits for the electricity generated by their share of the program. To date, as an example, there are more than 100 utility led community solar projects in the United States. As noted, utilities can also make investments in solar companies and solar projects and into funds that support investments in distributed solar.

With such investments, utilities can capitalize on new growth markets, earn a return on capital, and better understand how distributed solar markets are evolving. So, this concludes building block number five in our two-part series on building blocks for DPV deployment. After a short Q&A, please follow up with the contacts listed on the next slide with questions or inquiries about technical assistance opportunities. Thank you for your time.

Kala Thank you to each of the panelists for those outstanding presentations. As we shift to the Q&A, I would like to remind our attendees to please submit questions using the question pane at any time. We will also keep several links

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up on the screen throughout for quick reference that point you to where to find information on other upcoming and previously held webinars, including part one of this two-part series, and how to take advantage of the Ask an Expert program. We have some great questions from the audience that we'll use the remaining time to answer and discuss. The first question is—what is the best way to deal with existing DPV installation which did not go through the application's process and how do you deal with non-compliant installation?

Sherry Yeah, that's a really good question. We address that in a lot of locations around the world. There's a couple of different ways to address that. One of the ways is to basically do an amnesty program to allow a system that did not have to go through a process, but then are online a certain period of time in which to have their system inspected and then approved without any sort of penalty. And typically, after that period of time has gone through, then any other systems down on the grid can be disconnected by the utility.

A few countries are sticking the amnesty program and saying, "When the DPV rules are instituted, all systems must immediately be in compliance." That's a little bit hard to enforce, as you often don't know where the systems are located. And so, I think one of the models that used is amnesty just to locate by DPV is already on the system so that you can better control it.

Kala Great. Thank you, Sherry. Our second question is—if PPAs are not allowed, what are my options for installing solar?

Jason Sure. So, thank you for that question. If you are in a market where you cannot enter into these power purchase agreements, one of the first things to consider is the solar lease. Often times, the power purchase agreement is looked at as a sale of electricity, which is limited to the utility in that market. However, solar leasing is more of a transaction and a leasing of actual underlying equipment and not a sale of electricity.

And so, it might be a way to get around the limitations on PPA, but still enter into third-party transactions. If you're not able to do solar leases or power-purchase agreement, then you are looking at a marketplace where it is going to be direct purchase and financing of solar systems by the property owner, which would get us to those loan programs, those property-based financing opportunities, or alternatively, community solar, which might, again, be an opportunity in the absence of third-party business models.

Kala Great. Thank you, Jason. Our next question is—are there a lot of countries which do not provide any form of financial incentives through DPV?

Jason Certainly, there are countries that have not launched a distributed solar marketplace. There are countries that might have a utility scaled solar market, but, at the moment, do not have a distributed PV marketplace with established policies and procedures. I believe Peru would fall into that camp of a country with a utility scale market, but without a distributed solar market. Of course, even though you don't have a distributed solar market with specific policies, you may have certain tax exemptions and import tax exemptions that would

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apply to a distributed solar market if you were to create one. For example, I previously mentioned the concept of accelerated depreciation—that is a common investment-based incentive for investments in general and would apply to solar should there be a local solar and distributed photovoltaics' marketplace.

Kala Great. Thank you, Jason. Our next question is—how do solar storage systems/battery storage work in your structure you have outlined?

Sherry From a technology standpoint—and I'll maybe let Jason or Alex address this from more of a policy or financial standpoint—but from the technology standpoint, they're not significantly different in the permitting process. One area you see some additional requirements—and actually, for the building or construction code, there's often a lot of regulations—or there should be—around batteries, particularly when it comes to fire code and the National Electric Code. And so, how those are permitted—not from the utilities perspective, but more so from the local authority having jurisdiction perspective, is a little bit different. One way that they play in a little more with the utility—it just really depends on how a local utility looks at batteries, is it does give the utility a little bit more flexibility in how they interact with the DPV system if that's allowed through the regulatory process. For example—being able to store electricity and intentionally island the system—meaning you intentionally separate from the grid when the grid is down—has a whole different process than specifically working to never island your system and avoid those unintentional islands.

It's just a little bit different process in how the technology interacts with the grid, but the permitting process itself is not significantly different in most cases at this scale.

Jason From the finance and policy perspective, when we talk about including storage in a DPV project, you're certainly adding costs that need to be financed when you add storage to a project. And then, depending on how you're going to use that storage, there may be some cash flow benefits associated with the storage. For example—let's say you're in a market that doesn't allow exports of excess electricity to the grid; so rather than waste that electricity from your PV system, you could store it in an on-site battery and use that at a later time to lower your retail electricity bills. You may be in a market with what are called "Time of use" rates and may be able to generate power and save that electricity in a battery and sell it back to the electricity when time of rate use tariffs are high and improving your economics of the transaction of the project in general. However, you're looking at using storage purely for backup power purposes.

It is simply a cost from an economic perspective, however, you will receive resiliency benefits should the power go out, for example, if you are a super market and you're able to keep the lights on and keep the refrigerators working. So, you're going to save money in other areas by not losing power during a power outage. So, it really depends on the particular circumstance how storage will impact the financing and the economic return of your project.

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Alexandra And, to conclude, I think that this structure that we have here—these building blocks largely hold for storage as well. It's important to both understand one's vision and goals for storage, the definition, understand how the compensation mechanism is influenced by this new technology of battery storage. As Sherry mentioned, understand the interconnection process, and then Jason mentioned, the public policy support. So, we think that this structure is really useful for understanding distributed PV as well as additional technologies such as storage—that there are nuances within each of these building blocks that may change.

Kala Great. Thank you to all three panelists for that answer. We have another question of—how are interconnection timelines enforced?

Sherry "Not well" I think is the answer to that. There really hasn't been a great model of enforcement of timeline. They provide a good sort of framework in theory for goals, but realistically haven't been heavily enforced. That's why, on one of the slides, I showed that interconnection timelines are exceeded anywhere from like, 38 to 57 percent of the time. That largely is because they're not heavily enforced.

Kala Great. Thank you, Sherry. Our next question is—are tax credits and incentives available for community solar and group purchase projects?

Jason Yeah. They certainly are. Certainly, it's market dependent, but, for example, a community solar program or project will often be owned by a private solar developer, and this developer will monetize any available tax credit and incentives. And then, under a group buy, just as tax credits and incentives are available for an individual homeowner when he or she purchases a solar system, a group buy is simply a collection of these individual homeowners buying their systems at a discounted rate, and so, they will also benefit from whatever available tax credits and incentives are in place in that particular market.

Kala Great. Thank you, Jason and Sherry. Our next question is—what is the best metering option for a dwelling that has a rooftop PV and also connected to a grid or network?

Sherry That really depends. And different countries have different standards. Some countries use bidirectional meters that can measure both production from the system that is pushing towards the grid, as well as power from the utility to the home. Other countries require two meters—one that measures incoming electricity versus outgoing electricity. So, really, it just depends on what the local regulations say.

There's not necessarily a best solution. Whatever works best with the local utility is the best solution.

Alexandra And I'll follow up. As we discussed in the last webinar, metering options are a key part of compensation mechanisms. So, the type of metering that is required is going to depend on whether a country chooses a net metering, that billing option, or some sort of buy all/sell all arrangement

Kala Okay. Great. Thank you. Our next question is—in a typical streamline process, which entity is responsible for which step of the process?

Sherry Typical streamline. It really—that's going to change a little bit depending on the country context. I do want to start with that. But typically speaking, the utility is going to be responsible for viewing the application. Actually, I'll start at the beginning.

So, the installer is responsible for completing the application. Typically, that actually is the PV installer, not the actual customer themselves who would fill out an application. From there, it's the utility that screens the application where it comes to the interconnection between the two systems. So, that _____ common coupling where the DPV interacts with grid, and then, there is some sort of local authority that has jurisdiction meaning—in the US, that's typically a county inspector, state inspector—someone that has authority over building codes and construction process, and they're going to actually be the ones responsibilities for looking at the permitting around the construction of the system itself. Once it's reviewed by the utility, it's approved by the utility, often, that building permit is part—yeah, that building permit is part of the application process itself.

Once the system is installed, again, it's the utility that's typically responsible for looking and saying, "Yes, this was installed correctly" and getting that permission to operate. We see that in different countries fall to different entities. In some countries—for example, the local urban planning might be involved in the building process of that, or even in some countries—we worked with smaller countries—it even can go to the ministry of energy that has a division working on that. It depends on the country, but that's the typical process.

Kala Okay. Great. Thank you, Sherry. We have another question and the question is—in a regulated wholesale market with high hydropower installed capacity, cheap electricity prices, and where the state regulate and control electricity sector, which kinds of incentives should be most appropriate?

Jason In a market with low or cheap retail electricity prices, obviously making the economics work, given the cost of a solar system, is tougher than in markets with high electricity prices. And so, some of the incentives that I talked about in my presentation that revolve around reducing the upfront cost of the installed solar project will certainly make you better able to demonstrate a positive economic return when you're offsetting cheaper retail electricity prices. The same would go for tax credits and other incentives. And so, simply having cheap electricity prices doesn't necessarily preclude you from having a distributed solar marketplace, but you do need to consider if incentives are going to be required to motivate people to make the investment, given that the economics are less attractive. We've seen that you'll often have early adopters and folks who will install solar projects, even if they don't make pure economic sense, but historically, you haven't been able to build a robust market without the economics making sense for more people to participate in that market.

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Kala

Great. Thank you, Jason. It looks like we have time for one more question. The final question is—what happens to the solar systems in the utility rent-a-roof program at the end of the program?

Jason

That's a good question. So, when you read the terms and conditions of these various programs, sometimes, they will allow the opportunity for the homeowners to buy the systems from the utility either during the life of the transaction or at the end of the 20-year-term. Utilities will also offer the opportunity to remove that system from your roof. So, not unlike the end of term conditions in a power purchase agreement, the homeowners are likely going to have the opportunity to acquire that system at some discounted rate or ask that the utility remove that system.

Kala

Great. Thank you, Jason, and thank you, again, to the panelists for the informative Q&A session. Now, I'd like to provide the panelists with the opportunity to provide any additional or closing remarks you'd like to make before we close the webinar.

Alexandra

Thank you for your attendance today. Please, follow-up with the contacts listed on the previous slide with any questions and see you next time.

Sherry

Yeah. Again—thank you for your attendance today. And I know a lot of the technology questions were answered with "It depends on your local context" so if you have specific questions, please feel free to follow-up and we can address those questions more specifically to the context in which you're working.

Jason

And from my perspective, this is Jason. To the degree there's individual market questions surrounding the appropriateness, or the determination of what incentive might be most effective, feel free to send those inquiries as well.

Kala

Great. Thank you, all. And, on behalf of the Clean Energy Solutions Center, I'd like to extend a "Thank you" to all of our expert panelists and to our attendees for participating in today's webinar. We very much appreciate your time and hope, in return, there were some valuable insights that you can take back to your ministries, departments, or organizations. We also invite you to inform your colleagues and those in your networks about Solutions Center resources and services, including no-cost policy support through our Ask an Expert service.

I invite you to check the Solutions Center website if you would like to view the slides and listen to a recording of today's presentation, as well as previously held webinars. Additionally, you will find information on upcoming webinars and other training events. We are also now posting webinar recordings to the Clean Energy Solutions Center YouTube channel. Please allow for about one week for the audio recording to be posted. Finally, I would like to kindly ask you to take a moment to complete the short survey that will appear when we conclude the webinar. Please, enjoy the rest of your day and we hope to see you again at future Clean Energy Solutions Center events. This concludes our webinar.

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