Pacific Gas and Electric Company

Moderator: Izzy Carson
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OPERATOR: This is conference # 67753834.

Operator: Hello and welcome to today's Webcast. My name is (Paige) and I will be your event specialist today. All lines have been placed on mute to prevent any background noise. Please note that today's Webcast is being recorded.

During the presentation, we will have a question and answer session. You may ask questions at any time by sending them to drprfo@pg&e.com. If you would like to view the presentation in a full screen view, click the Full Screen button in the lower right hand corner of your screen, press the Escape key on your keyboard to return to your original view.

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It is now my pleasure to turn today's program over to Sandy Burns with PG&E. Sandy, the floor is yours.

Sandy Burns: Thank you and good morning everyone and welcome to our DRP Demo C Webinar and the purpose of today's Webinar is to give you an overview of the RFO we issued last week and to tell you what you need to know to put together a bid and what will happen to your bid when it's in our hands.

And I want to take care of a couple of housekeeping matters and then we will get to the description of the RFO itself and I will be assisted in this Webinar by several of my PG&E colleagues. So I am going to give you an introduction to the RFO and the process and then Michael Norbeck from our Grid Integration and Innovation Department.

We will describe the resource need and the load that we are trying to follow with DERs then I will talk about the solicitation process generally, then (Matt Braunwarth) will talk about a relatively new option we have for our behind the meter bidders to get PG&E support in acquiring customers. Andrew Lee will talk about the Term Sheet and the bid evaluation methodology and then, Izzy Carson will go over the details of the Offer Form and give you a demonstration of the spreadsheets and how to fill those out.

At the end, we will do Q&A. So go to the next one. So are we at the next one? So we are not taking questions on the phone during the Webinar, but at any time, you can send your email questions to drprfo@pg&e.com. And we are going to be compiling them as we go during the process and then, we will answer questions of general interest at the end.

I mean, if it is a very specific bit of question, we may try and answer it offline. And then after the Webinar, we will post the Q&A on our Web site. So we also post a list of attendees on PG&E's Web site as well, so if you don't want your name or the name of your company published, just send us an email to the DRP mailbox by Thursday, August 24th and then we will also have a recording of the Webinar on the Web site as well.

So some legal disclaimers, so this presentation is intended to provide a summary of the information and requirements set forth in the RFO materials, but you should carefully review the solicitation protocol and all the materials including the Term Sheet on PG&E's Web site and if there are any inconsistencies between the information that we provide in this presentation and the requirements and the RFO materials, the RFO written material govern.

So in terms of communication, we have all the information on our Web site, you will find the RFO materials and detailed instructions for submitting offers to power advocate and to the independent evaluator and we will also post updates and announcements on there as well.

And again, any communication that you have should be directed to the DRP mailbox with a copy to the independent evaluator.

OK, so turning to the schedule, our schedule is dictated by the CPUC decision approving Demo C, so we have crafted the RFO schedule to match specific milestones that are required by the CPUC. So specifically, that decision tells us when we need to execute contacts and file them for CPUC approval.

So we have developed the interim milestones such as the offer submittal date and the shortlisting date to ensure that we meet the CPUC mandated filing date for a completed contract, so today is August 22nd, your offers are due on September 29th on our power advocate Web site which is a Friday and in addition, you will need to send a flash drive of the offer to our independent evaluator, so he has it by the following Monday, October 2nd.

And it is part of Izzy's presentation. She will provide more detailed instructions about how to do that and it is also in the written solicitation protocol.

So we will be taking about two months to review all the offers, do our qualitative and quantitative evaluations and arrive at a shortlist in consultation with both the independent evaluator and the PRG.

And then we will negotiate with a subset of bidders, execute contract and file them for CPUC approval in April of next year.

So the decision also specifies when the DERs need to come online and the decision specifies that 20 months after the CPUC decision, so the CPUC decision 20 months from that is February 2019 and that's also only eight months after the CPUC approves the contract assuming the CPUC approves them very quickly on the schedule that they have identified in the decision.

And that creates some potential challenges, so the decision specifies that the resources need to be online within 20 months of the decision date which is in

2019, but the wires project that we filed as the DER alternative and which was approved by the CPUC wouldn't be online until 2020 and the 2020 date is because that's the year when load gets to the point that we need the distribution system upgrade.

So there may not be a benefit distribution deferral benefit in 2019 because the wires upgrade wouldn't be online. And so we recognize that the 2019 online date may be challenging. It is not very far away especially if DER providers don't begin substantial work on their projects until after the CPUC approves them and the CPUC approval won't happen until the middle of 2018 even if the CPUC stays on an accelerated scheduled for contractor view that is in the decision.

So in light of that fact, we are allowing you to submit offers for projects with 2019 or 2002 start dates or both. So right now, only a 2019 bid would be compliant with the CPUC decision, but we are looking for market feedback here.

If we have a consistent market response that shows that we have a lot of bidders proposing 2020 start dates or more than 2019 start dates or the 2020 start dates are significantly more cost effective, we would consult with the CPUC and see if we could get a waiver of the 2019 online date requirement, but it does bear repeating that the 2019 date is what we are working with right now. It is what is mandated by the PUC so if you can put together an offer with the 2019 start date and you can move up to the commitments in the Term Sheet for that offer, we encourage you to do so.

So at this point, one more slide -- so we have mentioned the independent evaluator several times, so the independent evaluator for this RFO is Alan Taylor of Sedway Consulting and the primary role of the IE is to just monitor what we do to make sure that our process is fair and all bidders are treated equally and consistently.

The IE also monitors our evaluation process and our negotiation and really to ensure that we have implemented what we said we were going to do in the RFO and we are doing what we said we would do and we are treating everyone consistently and that at end of the process, after we have executed the transactions, the IE reports on the process and the transactions that we are recommending for approval and basically whether he agrees that those transactions warrants CPUC approval.

So at this point, I am going to turn it over to Michael Norbeck and he is going to talk about the goals of DRP and specifically what the resource need is in the Chowchilla area and the specific distribution service that we are looking for.

Michael Norbeck: Great. Thank you, Sandy. Good morning everybody and thank you so much for having the time to join us today. We really appreciate it.

So when we talk about the DRP, I think this content is going to be pretty familiar to a lot of the folks that are tuning in with us today. You have seen the same slides the last Webinar we did and other public facing material we have presented to you.

Three major goals: One is to modernize the distribution system to accommodate our expected DER growth through two-way power flow; second is to enable customer choice for new electric DER technologies and services; and the third is to identify and develop opportunities for DERs to realize grid benefits, so it is all about figuring out how we integrate higher penetrations of DER on to our system and make sure that those DERs are realizing value for a variety of stakeholders.

When we talk about DERs, this technology stack of portfolios is going to be pretty familiar to folks again. If you can think about the distributed renewal regeneration, roof top solar PV is a common example there, energy storage; so you know, residential or utility scale, battery storage are raised, our one example, energy efficiency we consider to be DER; demand response and electric vehicles.

Straightening the slide, trying to catch up here, sorry guys. If I had hold music, I can play it for you. All right, for Demo C in particular, CPUC has directed us, this one with the California RUs to procure distribution services from third party owned DERs in order to demonstrate DER capabilities to defer traditional wires investments.

For two Demo projects, you know we are talking about Demo C here particularly. You know, we did talk to you about Demo D a couple of months back and today, we are talking about Demo C.

So for Demo C, we have selected the El Nido substation in Merced County, so Central Valley location for Demo C and we are targeting the deferral of El Nido transformer bank number one, our replacement project that is slated for the next couple of years, so this is what we are trying to defer via DER products and services.

In terms of specific loading objective for Demo C, pretty straightforward, four major categories. We want to validate DER distribution service capabilities, we want to source a localized DER portfolio via competitive solicitation which is what we are talking to you about today. We want to administer and operate a localized DER program at the utility and we want to validate locational net benefits as estimated by the indicative locational and net benefit analysis models, how do we put together via DRP Demo B.

So when we talk about the El Nido substation location, a few key points to bring your attention to. We are looking at 836 electric service points, so not super, super dense penetration here. It is a summer peaking area and we will talk a little bit more about the load dynamics in particular in another couple of slides, but again, a couple of key takeaways, a lot of agricultural interconnections here, 539 service points.

We are talking about dairies, ranches, poultry and groundwater pumping -- a lot of groundwater pumps in this area. We do have some residential and commercial, but these as we all see again in another couple of slides are not major contributors to load. I do want to point you towards that kind of gold colored triangle. That is the location of the substation. The two feeders that are of interest to us here are 1102 and 1104. Those are the feeders that feed the sub, so it's the blue and the red lines in the chart there.

Just waiting for the slide to catch up. OK, so talking about load dynamics here. We do have 64 percent of our service points as ag and they are 65 percent of our peak day demand, so again residential CNI, it exists, but it is not a major driver for us, you know, ag is going to be the sector that I think we see a lot of opportunity in terms of load management and DER product and service penetration for.

These next couple of charts give us a slightly different look at a similar set of data. So you can see here, ag is in blue, so if we talk about our historical peak load, this should be in the month of July as an example, the highest amount of bank loading we are seeing at 19 megawatts, the time of the peak is 6 p.m. and again, that big blue portion is our ag load so that is again, the most significant driver of our peak loading.

You see residential a little bit at the bottom there and green stays relatively flat, you know, ramps up a little bit towards the evening hours as well. Commercial and industrial also kind of coincides in peak with our agricultural load there, but again, these are going to be smaller overall drivers to our historical peak loading.

So this next slide will show us our summer months -- oh I am sorry, our shoulder months, forgive me. So significantly smaller overall peak looking at about 11 megawatts, very similar time of peak which is interesting, so semi-consistency there in terms of timing throughout the year for where our highest demand is going to be. It's 7 p.m. as opposed to 6 p.m., but again, the indicative month we are using here is May from last year.

So again, agricultural load is our primary driver. A little bit less than the differential between agricultural load and commercial and industrial in our shoulder months, but again, the most substantial contributor is going to be agricultural load to our peak load.

So this is a really quick slide, I just want to make sure we are covering the bases in terms of PV and demand response penetration participation in this area. Very limited number of PV interconnections and a relatively small amount of capacity there, less than 2 megawatts for the entire distribution planning area.

Demand response, pretty limited number of overall program participants and the reduction to peak demand so far has not been one that is going to show up in a significant way for us from our load management perspective.

So you know, potentially there is untapped potential. You know, it is hard to say for sure, but we can say that there is limited existing uptake for DER products and services in the (BPA) for now. Give me one sec, guys.

OK. So this is where it gets a lot more fun. Looking at the ox-and-whisker plot here, we are essentially focusing on our projected load profile for 2024. This sets us up in our shoulder month, so when we say shoulder, we mean, the months right around our summer months. This would be April, May and September.

The box-and-whisker again, you guys are probably familiar with how to read charts like this, but it shows us the total distribution of the expected peak loads for any given month hour in April, May and September as of 2024. The green dotted line is our bank capacity and planning limit and the other colored lines will make some more sense in another couple of slides to make sure you know what our product need is looking like, but those are the key variables to keep in mind for now.

So in the shoulder month, we would see that our peak load approaches -- actually, can you go back one more, a couple of bullets I forgot to mention. Thanks.

OK, thanks guys. So in our shoulder months, we have seen that the peak load approaches or exceeds our bank limit by less than a megawatt, about four hours per day again in the months of April, May and September.

As we touched on a little bit back, our load is driven primarily by ag and by ag pumping in particular, which means that we are much more sensitive to precipitation that's the temperature here. So we are looking at the summer peak, but it's not necessarily weather dependent.

It is going to be precipitation dependent, so as we think about products and services going forward, that's going to be the key variable and then kind of I think venue for constructive intervention is figuring out how to shape the ag pumping load and be sensitive to precipitation.

So when we get into the summer months, and forgive that's a typo on the slide here, it should say summer not shoulder, but the picture gets a lot more challenging for us. As we see, we are exceeding the bank limit by two to four megawatts nearly every hour of every day June through August.

So a much more complex picture for us. Again, our bank capacity planning limit is that green dotted line and we are well over it pretty much all the time, which makes this a very interesting project from a DER perspective.

So when we talk about the DER products and services, we are proposing to meet this need, I will start with our shoulder months here. First, we are looking at what we are calling a peaking capacity block.

This is one megawatt of capacity that we would need to have available between 5 and 9 p.m. for the month of April, May and September. The frequency line in the table at the bottom there, it looks like a lot of verbiage and I will kind of step us through it relatively slowly here because there is a lot of content.

So we are looking at a maximum of seven calls per month for April, May and September. A maximum of two consecutive days. Where it gets interesting is we are looking at a total of 50 calls per year during our active period, so we are going to need capacity in April, May, June, July, August and September, but our total number of calls for this peaking capacity block during that entire six-month period of 50.

We are looking at this as a kind of a pool that we will be able to draw from on a day ahead basis to call for that peaking capacity. Now, when we look at the allowable load increase, you know, this would -- it can't be a net load increase of course, but if we are talking about our permanent load shift, DER solution or charging a battery that would discharge, we would need the peaking capacity, we are seeing an allowable increase of up to a megawatt between 12 a.m. and 3 p.m. so most hours of the day, it would be acceptable to charge your battery or shift your load if we are talking about a permanent load shift product.

And so when we get into our summer months, and again, forgive me that should say summer and not shoulder up top, but when we get into our summer months, the product picture gets a little bit more complex as well. First, we are looking at what we are calling base load capacity. This would be our grey blocks. For the month of June that would be two megawatts, 24 hours, 30 days. For July and August, it would be four megawatts 24 hours, 31 days, so every day of the month.

We would also still be looking for the peaking block of one megawatt at capacity from 5 to 9 p.m., June, July and August. The 50 calls per year of course remains in effect, but we will be looking at a maximum of 15 calls per month as opposed to seven in the shoulder months and a maximum of seven consecutive days, so higher frequency, potentially greater consecutive number of calls, but again, total of 50 for an entire active period.

When we look at hours for allowable load increase, it gets a little bit more dynamic for us for June because we are sizing our base load capacity block a little bit smaller than July and August. Our allowable load increase hours are a little bit more limited so one megawatt for 1 a.m. to 6 a.m. in June that would still allow charging of a battery for discharge during peak or you know, overall one-for-one you know, peak load shift if -- load shift if you are talking about a permanent load shift solution for a DER product.

For July and August, again, the allowable load increase hours go back to 12 a.m. to 3 p.m., so good piece of time there.

I think that's pretty much all my content, right? Do we have one more? Are we done? Is that it, OK, cool, so I am going to turn it back over to Sandy.

Sandy Burns: OK, so I am going to give you an overview of the RFO design and then turn it over to the rest of the team for more details.

So this solicitation is very similar to what we did for Demo D and hereon, but we have made some changes based on what we learned as part of that process. So as a reminder, the product that we are buying here is distribution capacity in order to defer a wires investment.

And that's the only product we are buying. We are not by RA energy or racks. You are free to sell any of those products or monetize additional revenue streams as you can as long as you give us the product that we are looking for.

And we are offering a variety of delivery terms and with this aspect of the RFO, we are taking a somewhat different approach than we did with Demo C or with Demo D, sorry. So you can start in either 2019 or 2020 and regardless of when you start, the end date for your contract would be either 2024 or 2029.

So the 2024 end date would give us five years of distribution deferral value from 2020 through 2024 or the longer term contract would give us 10 years of deferral value from 2020 to 2029.

So in terms of size, we are looking for a minimum of half a megawatt, a maximum size of four megawatts for the base load and a megawatt for the peak and your offer should be given to us only in half megawatt increments, so you can give us a 3.5 megawatt offer, but we don’t want a 3.2 megawatt offer.

And your peak capacity offer should be the same for all the delivery months and all the delivery hours and for the length of the delivery term and for base load, it should be no more than two megawatts in June and four megawatts in July and August.

So there is no limit on the number of offers you can submit and you can make them either mutually inclusive or mutually exclusive. So one of the things that we learned from our Demo D is that it can be challenging for us to try and combine smaller offers to create a portfolio of resources that meets our need.

So we are encouraging you if possible to give us at least one offer variation that means the full four megawatts of base load or the one megawatt of peak and we are also interested in seeing smaller variations that we can combine from multiple parties, but if you can, we would like to see an offer that meets the full need, but again, if you don't think you have the capacity to provide that, then don't submit it.

So in terms of eligibility, any kind of DER is eligible as Michael kind of went through. Renewable DD, energy storage, energy efficiency, demand response, electric vehicles. You can be either in front of the meter or behind the meter. You can offer a single technology or a portfolio and if you are offering aggregation of multiple technologies, we ask you to tell us what those technologies are in your portfolio.

And again, you can offer a single resource or an aggregation.

So in terms of measurement and verification, as part of your offer, you should submit a measurement and verification plan with your offers. Projects that utilize existing protocols adopted by the CAISO and CPUC are preferred and that could be something as basic as you are using a CAISO revenue meter and behind the meters using a baseline methodology where you are comparing kind of days when we call you versus days when you are not called that may require a customized approach.

Interconnection, you have to be connected to one of the two feeders where we are looking for the distribution to furl. We don't have a specific milestone that is required to participate, but you are required to demonstrate to us that you can meet your online date.

And we do have a map, an ICA map on our Web site to give you an indicative understanding of the capacity that interconnect on the distribution lines in the Chowchilla area, but that is just indicative of what really will drive your interconnection as your interconnection study.

And then we are also concerned about double payments and double counting, so you are required to be fully or partially incremental to PG&E's programs, tariffs, and solicitations. So we have examples of that on our Web site and then we also ask you to submit Appendix B-5 to demonstrate how your offer is incremental.

And I am going to turn it over to (Matt Braunwarth) and he is going to talk a little bit more about incrementality.

(Matt Braunwarth): I'm sorry about this too. Yes, so it's me. I have some examples on the chart here of what would be considered fully incremental, partially incremental and what we are not considering incremental.

Fully incremental, things that are completely new. New programs, new technologies and things that are not in our current portfolio. They are just add-ons from DERs that just aren't deploying currently.

So at the other end of that spectrum, things that are not incremental are things that we offer already in our existing portfolio program, things that are being compensated under other solicitations or other programs such as SGIP or NEM and in between, will be partially incremental where we want to -- or need some information to make a determination is, is there something that is kind of an enhancement or an modification to the existing program that provides greater value that otherwise wouldn’t be provided and that's more of a case -- and that is reviewed by our team on a case by case basis.

And with that, we can move on to customer engagements report.

So as part of this solicitation, PG&E is providing or piloting an effort to provide customer engagement support through solicitation participants with the intent to improve the chances of program success and this offering should be very similar to what was also included in Demo D.

Given that outreach needs are unique and vary from program to program, PG&E is providing a variety of options for participants to choose from that best suit the needs of their proposed program. For all participants, PG&E will launch a Web page which will provide information about DRP demonstration projects and educate customers regarding the background and objectives of the program.

Following the successful execution of contracts with participants, customers in the area will then be able to validate information regarding the solicitation and participants' outreach efforts. This page will be located on the PG&E Web site.

Additionally, PG&E is offering further customer engagement support options and this will be offered in either a 50 or 200-hour allotment. PG&E support will take a variety of forms and does not have a set list of services due to variations in the types of customers targeted and interventions employed, but participants wishing to engage with PG&E, all the customer engagement support will need to provide a proposed customer engagement plan specific to those proposed program and provide detail on what PG&E resources would be required to execute that plan.

Example, potential activity could include call support, customer identification and evaluating potential co-branding opportunities. PG&E will not directly participants for these services, but in exchange, for the support division, we would expect to see the value of such support reflected in the participant's offers. Specifically, we'd require participants to provide two bid prices.

First bid price which presumes no support from PG&E and a second which reflects the value of the support which is being asked of PG&E to provide.

With that, the final scoping of support is subject to negotiation. Any support activities would not commence until the successful execution of a contract and PG&E does not guarantee any specific outcomes with the support and with that, I will hand over to Andrew.

Andrew Lee: Thanks, (Matt), so I am just going to go over the Term Sheet and the evaluation methodology on this RFO and as Sandy mentioned, the Term Sheet is posted online on the DRP Web site, so you know, please familiarize yourself with that material and this is just a high level overview of what is in it.

So the transaction is, you know, as Sandy was highlighting is it is really for distribution services. We are not looking to procure energy capacity, ancillary services or anything like that. Those other revenue streams are free for sellers to monetize. And so the distribution services, we are procuring or specifically you know, the base load product that Michael described as well as the peak product.

And so your contract can either be for one product or both depending on your offer and the transaction then is your obligation is to provide that product at a certain megawatt level which is the contract capacity. Anything above that contract's capacity, you can sell it to third parties and as mentioned, other attributes of the project that are related to that product can also be sold to third parties.

So just to go over the products again that you can provide, so the base load capacity is essentially you know the 24/7 need for June, July and August. You will have to dispatch your resource every single hour of those months in order to provide the distribution services. The peak capacity is a little bit narrower, it is a 5 to 9 p.m. requirement between April and September.

As Michael mentioned, we can dispatch this resource you know, up to 50 times per year and in the shoulder months of April, May and September that can be up to seven times a month and up to two consecutive days. For the summer months of June, July and August, we can dispatch up to 15 times a month up to seven consecutive days.

And the way the dispatch would work is similar to what we structured in Demo D which is you know, PG&E will give sellers a day ahead call by 8 a.m. of whether or not they need the peak capacity and you know that can be either verbal or electronic or signal up to PG&E's discretion.

And other requirements of the project is for sellers to provide PG&E real-time visibility into the performance of the DER and this would require installing certain communications and equipment for us so that we remotely monitor you know, how the aggregation or how the resource is performing.

And you know, one thing that you must notice for the restricted -- our restricted periods for this peak product, you know, basically if you are shifting load or charging a battery, you have certain periods where you can't increase load and that is obviously consistent with the need for the 24/7 base load product.

And so you know, we have carved out certain hours in June, July and August where you can actually increase load.

So the way that you would be paid for your services is a fixed capacity payment. For the base load product, this would just be a simple you know, a fixed price dollars per kilowatt month. For the distribution peak capacity, you can also bid in a variable price which would be dollars per kilowatt hour price for you know, whenever the peak capacity is actually dispatched.

The capacity payment will be reduced depending on how you perform for a month and this table just illustrates you know, the ratio of payment deductions that would occur if you performed less than 100 percent.

So for your project saving customer acquisition that is 100 percent responsibility of the seller. As (Matt) mentioned, we would provide certain amount of hours of customer engagement support if so chosen, however that doesn't guarantee any customer acquisition and so we want to make that clear that sellers are the ones who are solely responsible for acquiring customers.

You know, given that you guys can also swap customers in and out as long as it is in accordance with our Safety Provisions and satisfies you know, our incrementality criteria where there are no double payments or you know double counting.

Any type of marketing materials created by a seller is subject to PG&E written approval and again, you know, sellers are responsible for all of those activities as well provided that PG&E may provide certain hours of customer support.

So within this solicitation, we are requiring performance assurance and there are two different types, one is project development security which is performed assurance prior to the delivery date and the other is delivery term security which would be performance assurance after the delivery date.

And so you can see these amounts here for the project development security at $60.00 per kilowatt for all new resources and $25.00 per kilowatt for existing resources. And for delivery term security, the amount would be $125.00 per kilowatt or 10 percent of the highest you know, three-year period and that's the maximum of these two numbers.

So within this section as well, there is a termination payment if there is an event to default by the seller; or actually, in either case and basically, the defaulting party would owe the non-defaulting party the amount in accordance with the performance assurance.

So there are certain conditions precedent that must occur before the contract, you know, becomes effective. And so, the first one obviously is CPUC approval has to occur and we have given a timeline of 180 days after which either party can terminate the agreement.

For specific seller condition precedent, things that have to occur before the delivery date are you know, obviously, the project has to be constructed and we have to feel comfortable that there is an attestation from an independent engineer that it has been constructed safely. The project has to pass the performance test demonstrating that it can perform the distribution services.

You have to have provided us, you know, the list of all the customers that are included in the project if you are behind the meter and we have to have verified that those are incremental and measurable and also, sellers will have posted the performance assurance.

So there are certain performance requirements of this contract as well and you know, failure to meet these requirements could trigger an event to default and so, this is not an exhaustive list. Obviously, these are some of the key ones for Demo C and so, you know, we want to ensure that these projects can come online and that you know, we are comfortable that they will be there and be able to defer the distribution investment.

And so, you know, failure to meet a critical milestone or the initial build entry date would be considered an event to default in this case because you know, we need to be able to plan for a backup option if these resources don't show up.

Similarly, you know, we need them to perform while they are in the delivery term and so, you know, if you aren't able to consistently perform when we call you and if you can't meet at least 75 percent of the distribution services factor, then that could be an event to default.

Similarly, if you have performed -- we run a performance test on the resource and it doesn't perform up to 85 percent that could be an event to default as well.

And because you know, we don't want these DERs to exacerbate existing problems, you know meant to help defer distribution investment, you know, we don't want DERs operating in the restricted periods, and so if you do that consistently that would also be an event to default.

And so with that, we will just go through what the evaluation methodology is for this Demo. So the main quantitative factors you know, as we have discussed is it is really the distribution deferral value. There are no market products that we are procuring here, and so the main quantitative factor will be you know, the amount of distribution investment that your project is able to defer.

We will compare that value against other costs such as the contract payments, you know, the customer engagement cost that you have identified as well as administrative costs for managing these contracts.

Qualitative factors that we will look at are going to be project liability and this includes you know, the type of technology you use, your interconnection, the ability to meet milestones, which include, you know, site control and customer acquisition plans and we will also look at developer experience as part of project liability.

Other qualitative factors will just be, you know, the credit of your company that is developing the project and also diversity among technology and counterparties and whether you are a small business enterprise.

And we will take all of these factors and essentially rank them on a least cost benefit basis and that is how we will develop the short list.

And so with that, I will turn it over to Izzy who will go through actually how to fill out one of these Offer Forms.

Izzy Carson: All right, thanks Andrew. So offers must be submitted via the online platform Power Advocate. Registration is required in order to submit an offer. Register through Power Advocate at the link displayed on the screen, also posted on PG&E's DRP Web site.

The offer submittal deadline is 1 p.m. on Friday, September 29th. Power Advocate will not accept offers beyond that 1 p.m. offer submittal deadline. We strongly encourage you to register well in advance of the offer due date and we will only consider offers that as of the submittal deadline are complete and conforming offers.

In addition to the submission of offers through Power Advocate, participants might simultaneously submit their offer materials to the IE on a USB flash drive for physical delivery no later than one business day following the Power Advocate offer submission deadline, i.e., October 2nd, 2017, the following Monday.

The participant's flash drive must contain the same materials that were submitted through Power Advocate and must be send to the IE at the Sedway Consulting address displayed on the screen and it is also posted through our Web site.

If offer documents are found to be incomplete or have errors, PG&E will notify the participant via email and allow two business days to correct. By submitting an offer into this RFO, each participant is required to abide by the Confidentiality Obligations specified in the protocol.

Some may choose to bid multiple offers with variations including delivery term with the option of the 2019 or 2020 start year and delivery term of five or 10 years. Customer engagement support available at zero, 50, or 200 hours support available for behind the meter offers and pricing. The specific capacity prices in dollar per kilowatt month and a variable price in dollar per kilowatt hour.

The distribution resources planned protocol outlines the documents required as part of the offer package and specifies the format for each. Required documents for offer submission are listed here and include the introductory letter. We definitely encourage you to spend time on this letter that helps us understand your offer. Specifics are incredibly important.

Fully completed Offer Form which we will go over in more detail, a supplemental RFO appendix document includes a number of appendices to help us understand the specifics of your offer. Project description, site control, milestones, experience and qualifications, resource double payment, double counting, organization information -- everything included in that appendix document and interconnection studies if applicable.

Please confirm that your documents are in a specified Excel, PDF or Word format prior to submitting your offer package.

The Offer Form is structured with the following tabs. We will go through the majority of these in the subsequent slide. For reference, the tabs displayed at the bottom of the screen are shown as they appear on the Offer Form. Participant information, project description, pricing sheet, and supply chain responsibility all have fillable fields.

Starting with the Instructions tab, we want to emphasize the importance of enabling macros before you start. Many of the cells within the Offer Form are linked and will display an error message or will lock the cell entirely if macros are not enabled.

Be sure to enable macros when opening the form before any entries are made. Please make sure you save and submit the form in a Microsoft Excel dot XLSB format. Each cell with the yellow background must be filled out. Once completed, the yellow background will disappear and the number of missing inputs will sit at the top of the screen will go down.

The word "Complete" will show at the top of each page once all the yellow fields have been completed. Ensure that the word "Complete" appears at the top of each page prior to submitting your Offer Form.

There is also a Validation tab following the Instructions tab that will show the status of each page and whether the Offer Form in its entirety is complete.

In the Participant Information tab, note that the counterparty/legal entity name, look here at the top left here, the legal entity that should be entered will be the legal name that would be signing the contract if the project were to be selected. Please include at least one authorized contact in the Developer Information Section. Note that the contact that you list here will be copied in email communication with PG&E.

The Participant Information tab also includes several attestations and affirmations specific to and/or new to this RFO.

The Project Description tab will allow you to the detail the actual specifics of your project. Your bid ID will be created at the top of the page as you populate specific fields for your offer. Once the required fields have been entered, we ask that you save your file, naming it to match your bid ID.

There is a Copy Bid ID button directly to the right of your bid ID that will simplify naming the file to match your bid ID.

If your offer is mutually inclusive or exclusive to any other offers you have submitted, select the option from the dropdown. You will also be asked to describe that relationship between your offers. Also in the Product Description, you will have the option of submitting an offer for peak capacity, base load capacity or both.

Starting with peak capacity, you will first select the term, either five or 10-year deferral values starting in either 2019 or 2020. The delivery hours are set to the need of 5 to 9 p.m. every day of the week in April through September. Although PG&E is peaking at one megawatt reduction in net loading, you bid may be in increments of half a megawatt up to the full one megawatt need.

You will need to select the technology and corresponding capacity that you entered. It needs to match the contract capacity entered above.

Similarly, for base load capacity, you will first select the term again in either five or 10-year deferral value starting either 2019 or 2020. Delivery hours here are set to 24/7 every day of the week in June, July and August.

Although again, although PG&E is selecting a reduction in net loading varying between two megawatts and four megawatts, your bid may be in any increment of half megawatt up to the full need. Select the technology and match the contract capacity that you have reflected above.

On the Pricing tab, the customer engagement support option is only available for behind the meter projects and will be grayed out for in front of the meter projects. On this tab, enter your fixed capacity price in dollar per kilowatt month for each month and year of your offer and enter your variable pricing in dollar per kilowatt hour for each month and year of your offer.

And that concludes our presentation. We will take a brief 5 to 10-minute intermission at this point, when we return, we will answer any questions that have come in to the DRP mailbox during the Webinar at drprfo@pg&e.com. Thank you.

Izzy Carson: Thank you for sticking with us through that intermission. We have got a number of questions through the mailbox and we will try to go through them. We have grouped them together here, so a number of different people will be speaking in the room.

We will start off with Michael.

Michael Norbeck: Sure. Thanks, guys. You guys sent us a lot of great questions. Certainly, more than we thought during the Demo D Webinar which I am taking is a good sign that you all were paying attention during the conference. Thank you.

All right, so just to summarize a couple of ones that we got that I will tackle for us first and then we will move on to a few of the other subject matter experts in the room.

One question, the Demo C integration capacity map shows the City of Chowchilla and the target area. The city appears to have over 3,600 households, so curious how the number compares to the 227 residential service points shared in the Webinar. Can you please clarify? Great question.

The customers that are interested in this particular deferral opportunity are the ones tied to feeders 1102 and 1104, which are the feeders that exceed the bank one that we are looking to defer the upgrade on.

So the other residential customers in the City of Chowchilla are not going to be on those two feeders and are not going to be on that bank. So that's the reason for that, I guess difference in the number of residential customers we are talking about.

Second question that I will tackle for us, the following chart shared was to provide conflicting info on the residential contributions to peak load. It will show residential load, it is 40 percent of peak but the pie chart does not align. Please clarify? Great call out.

Thank you, that's our bad. Data discrepancy. The pie chart is going to be the relevant one that will align to the kind of the stack load profile that you will see in the following two slides. The chart has a typo on which we will clarify, correct and repost on to the Web site, so you will have numbers that match so it's a great iteration of the slide. Thank you for calling that out.

Can you please offer any more information on the residential service points? Specific data of interest percent with central AC percent using electricity for water and heat. Great questions. Here, the customer data privacy and sharing are restrictions that we find ourselves under. We are not going to be able to share that, I guess, granularity of data. Great questions we know that would help you start your bid that much more effectively.

Unfortunately, we have limited wiggle room there, so we won't be able to get into that level of detail with you.

Has PG&E run any residential DR programs in this area that can offer an expected load drop per customer? That's a good question. We will refer you back to the content in the Webinar deck, so again, existing DR on this particular bank in terms of customers that are tied to it. Relatively limited, right? So contribution to peak, negligible, and I am going to say 41 or so DR program to this effect. So pretty straightforward answer to that question.

Izzy Carson: Oh great. Now, we will move to Sandy.

Sandy Burns: OK, so I am going to take care of some eligibility questions. So the first question was, do you have to have a customer and project site identified prior to submitting the bid or can we submit a bid and then find the site?

So you don’t have to have a customer in mind or signed up when you submit your bid, but we are looking at assessing project liability, so if you do have say a front of the meter site and you have site control and further along, say you have interconnection progress, we will look at you as more viable than if you haven't done anything yet and you are still looking for a customer and a site, but you certainly can submit a bid without those items.

And then for behind the meter energy storage, is there a specified technology that is preferred? And the answer to that is no in general. We don’t have a specific technology of any kind, either front of the meter or behind the meter preferred.

Our only concern is whether you can meet the operating requirements that we have laid out in the RFO.

And then, a related question for base load, is it supposed to be behind the meter? And the answer to that is no. For either one, you can be behind the meter or in front of the meter, any technology front or behind the meter.

OK, and so now Andrew is going to answer a few questions.

Andrew Lee: Sure thing, Sandy. So the first question is does delivering in 2019 have a contingency value since the deferral need isn't until 2020? The answer to that is no, we are not going to be assigning any contingency value for 2019.

So the second question is for behind the meter energy storage. Will the seller be charged for the cost of charging the battery? The answer to this is no as well and it is not just behind the meter. It is also, you know, in front of the meter as well.

Sellers are responsible for those costs, all we are procuring in this solicitation is the distribution service and so, you know, if sellers felt the need to price that in, they could do that either through the fixed price or the variable price.

So related to that is, will the contract be structured as a tolling agreement or -- and the answer to that is no or yes and no in the sense that tolling in the sense that we -- for the peak capacity product, we will tell you when we want to dispatch, however that is limited to the 5 to 9 p.m. timeframe.

However, you know, we would not be responsible for any of the charging energy or cost associated with that, and so that is really on the seller.

So the next question then is, can you explain what the fixed price dollar per kilowatt month is and how is the variable site calculated? So these are just prices that we are expecting sellers to provide to us as part of their offer.

Sellers can choose you know, essentially the way we would pay the contract is on a dollar per kilowatt month basis and the way the variable price would work for the peak product is any time you are dispatched. You know, let's say you are dispatched per megawatt and you delivered a megawatt, you would be paid the variable price for that megawatt on a dollar per kilowatt hour basis.

So if you were dispatched for the full four hours, you would be paid for on basically four megawatt hours and then you'd convert that to the dollar per kilowatt hour price.

And so the next questions will be dealt with on customer engagement and incrementality and (Matt) will take care of those.

Matt Braunwarth: All right, we had a few questions on data access specifically around getting access to customer (AMI) data or their load profile and as part of customer engagement, we can definitely help kind of with that process, but in terms of kind of actual access to data, access to load profiles or (AMI) data is something that has to happen after we have a signed contract.

So there are public data sources available. I think we have referenced them on our Web site to kind of help aid you in putting your bid together. But actual access to data requires a contract in hand to do that.

We have had several questions come in regarding incrementality around SGIP and NEM and it definitely is not a clear topic, but just to say again, projects or programs that are participating in NEM or in SGIP without any modification that are then trying to apply to this pilot are wholly not incremental.

What we are looking for is information that would be provided to us that helps justify what has been changed or modified as providing extra value outside of that which that portion could then be considered incremental as part of this pilot.

And then moving on, we had another question around a specific pump repair, EE measure is that -- would that be considered incremental and our response would be it is a maybe depending on how the specifics of the program and how it lines up with what is offered in our existing portfolio could or could not be considered incremental and we just need more information to be able to make that determination.

Izzy Carson: So one more.

Sandy Burns: Go ahead, one additional question came in just give us one moment here.

Matt Braunwarth: We had another question around, do customers have to be spread out across different sectors i.e. residential, industrial, commercial or can they all come from one source? The answer is they can be spread out or come from one source. It does not matter.

Izzy Carson: OK, great so that takes care of all of the questions that have come into our box during the intermission. If you have any additional questions, definitely feel free to send them our drprfo@pg&e.com mailbox. We will be posting a list to the Web site that contains all the questions that have come in and these two sections and again, thank you for your participation this morning. Bye-bye.

Sandy Burns: Thanks.

Operator: Thanks to all our participants for joining us today. We hope you found this Webcast presentation informative. This concludes our Webcast, you may now disconnect.

Have a great day.

END