[Speaker: Kristen Ardani]
Cover Slide:

Thank you everyone for joining us today for our DG interconnection collaborative informational webinar. Today we are going to talk about minimum day time load calculation and screening procedures and their role in the distributed PV interconnection process. We're going to hear from Babak Enayati of the Massachusetts Technical Standards Review Group and the group's recommendation to adopt 100 percent minimum daytime load screenings in Massachusetts. And then we're going to hear specific examples from an electric utility and mature solar market, Hawaiian Electric Company.

Slide 2: So with that I would like to introduce our speakers. We'll have Dr. Dora Nakafuji. She's the Director of Renewable Energy Planning in the system's integration department at HECO. She has over 13 years of experience working in renewable integration and wind energy research.

Her efforts include working with various states and national energy efforts to foster collaborations with utilities and industries to deploy smart technologies and sustainably meet energy policy goals. Prior to joining HECO Dora was a staff researcher at Lawrence Livermore National Laboratory.

We also have with us today Anthony Hong, the Director of Distribution Planning at HECO. His group is responsible for planning distribution infrastructure on the island of Oahu, including review and planning or interconnection requirements and studies for distributed resources.

Then we will hear from Babak Enayati. He is currently a senior protection engineer at national grid where he is responsible for design and review of the protection relays for distributed generation interconnections in New England. He's also the chair of the Massachusetts Technical Standards Review Group and vice chair of IEEEPES Boston Chapter.

Besides protection engineering over the past nine years Babak has worked on controlled microgrids, optimization of electrical drives, multigeneration power system dynamics analysis and other areas

of distributed generation research. So with that I'm going to turn it over to HECO.

[Speaker: Anthony Hong]

Slide 3:

Well thank you. This is Anthony Hong and thank you for everyone that called in today to participate in the webcast. Thank you for having me present today. My name is Anthony Hong and I'm with the Hawaiian Electric Company, I'm a principle engineer with Hawaii Electric. And if you're not familiar with the Hawaii islands, we serve four island Oahu, island Hawaii and island Maui and Molokai. I live in Oahu basically the most populated island and that's where I locate and we talk most about today on that how electric islands.

Slide 4:

Today we'll talk about minimum load but before I get into daytime minimum load we'll give you a little background of Hawaii distribution system and we'll talk a little bit about distribution planning criteria and why it is so important to look at roles both at net load and then I think after that Dora we pick up the next step approach and data.

Slide 5:

So what is the distribution system? In Hawaii the distribution system we talk about a lot of utilities have different voltage or different ways set up. But in Hawaii we have on the left side which is a generation power plant, generation, most generation steam unit. Then we step up to 138 volt as the transmission system throughout the island and then we have transformers step it out from 46 kV from 138 kV to 46 kV and we did two systems. We call that as a sub-transmission system and then we step out from 46 kV to 25 kV or 12 kV or 4 kV depending on the area and then we distribute to the customer. When we talk about the distribution system we talk about anything below 46 kV and as of today the majority of our distributed generation are connected to the distribution system and the 46 kV, majority are connected there.

Slide 6:

In planning, we usually plan based on the predicted load, peak load of the system so that's how most of the planning we do here we predict a peak load and we plan based on that and if any normal capacity exceeded or maximum capacity exceeded we create projects to plan ahead to upgrade it, what we need. Mainly we have to make sure the voltage is under the tariff limit which is about plus or minus five percent of the nominal voltage. The unique of the Hawaii system is we have, our feeder is very short. It's not – probably the longest feeder we have is about five miles and most of the feeder we actually have a really live of what we call a strong backbone on it.

Slide 7:

For regional forecasting, it's very difficult to forecast more than five years recently because a lot of development on the island depending on the area of the island, very dynamic. The lower changing and lower added to island to people propose hotel or different thing or different area of island so it's very difficult to plan anything exceeds five years so we normally do our planning within a five year period.

Slide 8:

So what is our Hawaii condition of today? This chart will tell you. You can see that from 2005 our distribution, majority of PV and majority of rooftop in Hawaii increasing almost double every year from 2005 to 2013. At the end of 2013 we have about 300 megawatts of PV connected to our distribution system and just to put it in context our Hawaii electric, our capacity is 1200 megawatts capacity and as of last year we have 221 megawatts of PV connected to our system which is about 17 percent of our maximum load capacity. That is just like have two power plants or one big power plant on the grid connected to the grid and we have any –pretty much no control of it so the arrogate amount of the PV is the major concern for us so…

Slide 9:

This is just to show you what, how the PV behaves vary during the day. This is one example of one of the feeder circuits that we have,

a feeder we have on the island and depending on the day sometimes sunny day or cloudy day you have the amount of peak production and it's very varied and it's almost vary. During the time of 9:00 to 5:00 PM it just picked up and it just went away. It picks up, depends on how much it picks up. It depends on the condition of the sun.

Slide 10:

So to have better planning we have characterized each feeder, understand each feeder, the characteristic of each feeder and you can see that the commercial feeder has behaved differently and have different characteristics from the residential feeder and also industrial feeder. For commercial feeder you can see that the yellow graphics on the top it's just got smooth throughout the day. The PV connected from the period of 9:00 to 5:00 PM it just smoothes the curve out. But for the residential feeder when in the early morning from 5:00 to7:00 AM in the morning we have some kind of peak there, if you woke up and started to make breakfast and coffee and you have a little bit of peak there and then during the daytime when people left, go to work from 9:00 to 3:00 PM the load demands start to drop because PV starts to come up and then start to drop.

In a lot of case some of our feeder actually drop below and become reverse power feeding back to the substations. And then in the evening after 3:00 you can see the curve, the graph here, the PV start to dive out and then people start to finish work and go home and start turn on the AC, start cooking. The peaks drop dramatically, the demand, the load demand starts to go up really high. That is the operational challenge for us to try to ram up and feed that load-demand right there, the evening peak.

Slide 11:

This is the look at another level, sub-transmission level which is for the 6 kV level and you can see that from year to year in 2010 where not too many PV on the system yet you can see that the curve, the purple curve, the top have easy to manage, operate. It doesn't have the impact of the daytime from 9:00 to 5:00 but as more and more PV connect to our system as of 2013, 2012 you can see that during the period of 10:00 to 2:00 PM, 10:00 AM to 2:00

PM the demands start to drop dramatically almost to a certain point that we reverse power feedback to the transmission system. This is just a very typical industry called a duck curve and the duck is actually in Hawaii already. We already see the duck and we've feed our duck pretty well that have good belly there.

Slide 12:

To help the public and other people understand we also have this online renewable energy watch that people can log in to web on the internet to see how our energy uses for the day renewable energy and they can see that the net load which is what we measure coming from the SCADA compared to the actual gross load, that's the one that we need to figure out what's actually behind that because the gross load are the load that we need to serve if PV go away. And this is just some information we put outside for the public and also inside company so everybody can see how everything behaves.

Slide 13:

This is another look at how the impact of PV through our system. Certain time, most of the time most of the utilities we see nighttime loads are lowest, the minimum load but for us now in some circuits or some feeder actually the daytime minimum load is actually lower than the nighttime minimum load because of all the PV generation feeding into the circuit.

Slide 14:

This is called business slide but the main point here I want to point out is during the clear day or sunny day you can see that the green line, the green graph, that's what we see from the SCADA from the reading we have from the station. We call it net load and the red one is actually the gross load. The bottom you can see the cloudy day when the PV is not generated our customers still expect us to serve that load so we need to really figure out, understand what is the actual gross load on our system besides the measurement. What we measure usually is just the net load and you can see that the more and more the PV generation connects to our system the gaps getting bigger and bigger from the red and the green line. So this is a lot more important for us to understand and

know what is a gross load that we actually have that we have to serve if the PV are not there.

Slide 15:

So that is why we need to know that. So the way we do to figure out what's the gross load there's a lot of different ways to do it because most of our system, not all of them get measurement, have measurement device on it and some have some measurement device, some don't. So it really depends on the availability of data we have to figure out what is the actual gross load on that feeder. And if we have the measure that's good we can do some calculations and different methods we can use. If we have only some data then we have to do some estimates to figure out what the gross load. But if we don't have any data at all then we have to do some kind of proxy to figure out that gross load that we have on that feeder.

Some of our area we also install the irradiance data so we can collect and so we can help to figure out what the generation, PV generation in that area. If we have that it would be great. We can know what to calculate, the gross load. So basically the gross load is equal to the net daytime minimum load. We have to look at the daytime between 10:00 and – 10:00 AM to 2:00 PM and then you add back PV generation during that time then you have the net minimum load so that's a basic concept that we have to try to figure out and depending on the data we have how we calculate that.

Slide 16:

So one of the methods we have if we have measurements, we have measured data what we do with the measurement data is what you have as the net daytime load during 10:00 to 2:00 and that usually comes from the SCADA of substations that you have and then you can use the solar irradiance data, you have that. Then you can combine that with figure out what is the PV generation will be on that time of the day that you picked for the net daytime minimum load and you add it back to the net minimum load to calculate your gross daytime minimum load. So if you have data that would be –

this is just the formula you can follow, we follow and figure out what's the daytime gross minimum load.

Slide 17:

In this scenario we don't have too much data. We have some data. Like for example you have, we don't have the net, the measured data for the feeder but you have the measured data for your substations and what we do – you might get some spot readings for the feeder and calculate the ratio for that transformer. How much goes to this feeder? How much goes to the other feeder? And by that way you can see now what the feeder net load the feeder. And then in this case most of the time we don't have the any sense for the irradiance also and in that case what you do is – what we do, we depend on the area of the feeder we just add back certain percentages of PV generation to the net load we have.

For example if we have, we know the region has a lot of clouds and normally wet then we add less percentage back PV install back to the net minimum load. But if we know the area has most of the time sunny we use a different percentage to add back the percent of PV installed added back to the net minimum load. So it really varies depending on – you need to understand your area, your region. You need to understand the characteristics of the feeder to carry out, determine how much percent of PV you add back, we add back to the net minimum load.

Another way to do it – I did not have it on this slide but we also do here is to look back the historical data. You have like the transformer data. You're looking back to historical for 2004 – 2005 where PV is not too many PV into the system yet and figure out the correlation between the peak and the minimum load, percent at peak between the peak and minimum load and you use a percentage for that feeder and apply it for current year because the peaks normally don't change too much. The peak has usually been the peak for us so there's no PV at all and you can find the correlation between the peak and the minimum load, the daytime minimum load at the historical base and then you can apply the same ratio to our current, that same feeder for a current year. That's another way to do it.

Slide 18:

In a scenario that you don't have any data at all for the feeder, what we can do – fortunately we don't have too many of those but what we can do is we have to do some kind of proxy. Basically we have to look at the feeder, at feeder number one. We look at the characteristic of it. If it's mostly a residential type characteristic or commercial type characteristic or industrial type, depending on what characteristics of that feeder by looking at your customers connected to that feeder. Then look for a similar feeder, similar characteristics or similar feeder to in a system and kind of look at the ratio of how the behavior of those, of the feeder you have data on and figure out that ratio between peak and daytime minimum load of that feeder and you can apply the similar ratio to the feeder you have, feeder one, which we don't have any data on.

For example I think if you have for feeder one you know that you have ten watt of, for example, ten megawatt of residential connected to that feeder for the peak load and then you have comparing normally have four megawatt of minimum load during daytime for that feeder so peak at ten and four at the minimum load. You can use that basically 40 percent of the peak that can come up to figure out your minimum load. So look at feeder one at the customer meters connected to that. You know that you have about six megawatts of peak on feeder one. You probably figure out that your daytime minimum 40 percent of that is probably your daytime minimum load. So it's different methods of trying to figure out and a lot of them is assumptions. A lot of them is approximate. But unless we get some way to figure out what exactly the gross daytime behind that so we can do our planning based on that.

Slide 19:

So basically before any PV come online our SCADA load coming in is equal to the system net load and the system net load basically also equal to the gross load but as PV come in now they – that formula is no longer valid. So the gross daytime, the gross load that you have right now is actually the system net load plus whatever PV generation, the sum of PV generation you have on that feeder so you have to figure out that too to have the real gross load.

Slide 20:

At this time I will turn it over to Dora to continue on the presentation. Dora are you there?

[Speaker: Dora Nakfuji]

Hi everyone. Sorry. Am I coming through?

[Speaker: Anthony Hong]

Yes, you are now.

[Speaker: Dora Nakfuji]

Ok. Great. So, Anthony kind of walked you through various ways to calculate and distinguish the net load and the gross load and a couple of things I just wanted to mention is that our goal is to get additional irradiance coverage all of our islands so that we have adequate ways to estimate that solar generation from the various distributed PV systems. And so my group is the renewable energy planning group so we do work hand in hand with our transmission distribution planning folks and provide them the information so that they can continue to make the, do the planning on the infrastructure and assess the conditions.

So one of the things that we've noted too is that because in a prior slide we showed a clear day and a cloudy day condition you can see for the cloudy day conditions that the load does go up on our feeders and it shows that we are serving that amount of load and so over time as we track that for the different seasons of the year and in Hawaii we do have seasonality. We have a wet season and a dry season, not always sunny. We do get that condition of a cloudy day. And so that's another way we can also begin to track the load, the gross load that's served by that feeder as more changes come onto our system, as more loads are connected to our distribution or if loads get, go off of our system. So those are all ways to use the information that we're gathering from the field so that there is a little bit more resolution as well as the assumptions are further quantified so that we use real data from the field.

What we've done with a lot of the information on these feeders is now presented it in these visual maps called the locational value maps, LVMs. And they help us, one, communicate internally as to

which circuits and feeders are close to thresholds that require additional study based on interconnection or other concerns on the system so system level impacts as well as distribution level impacts. I'll talk about that a little bit more. The maps are also a great way for us to communicate a lot of this information to the developers and the general public because what they also want to know is the impact of these high penetration on the timing of getting them connected, getting their systems online so from that standpoint it impacts their timing and ability to use their panels.

So what we've found is that the use of the peak load conditions – so this map, actually the orange map we called it. I color coded it. You can see the gradations. The calculation here is the percentage of distributed PVs based on the installed feeder PV capacity megawatts divided by the peak load on the feeder which is something that we measure on the system. And that peak is usually at night and per Anthony's discussion the load profile is the evening load peak tends to be the highest on our system. However not all circuits have a peak at night. The commercial circuit that Anthony illustrated earlier the peak was during the day and so for those circuits the peak will be captured based on the highest reading we have on that profile.

So this map kind of shows that gradation and you can see on the legend on the right the different levels that we show. And these maps are also updated on a nightly basis on the island of Oahu and for our neighbor islands' utilities we update them on a monthly basis. And you see that the box that's highlighted, that's the range that was typically the grouping that was greater than 15 percent per our Rule 14H interconnection standards. Many states and locations have a 15 percent review threshold for interconnection studies and so what we wanted to just show is that above that 15 percent you can see that the circuits have further levels of gradation and those ones that are above 75 percent penetration of peak meter loads, we have them. So it's a reality we're facing.

Slide 21:

So this slide we call it the blue slide and color scheme was – I think we followed the same as the peak. However this time the penetration levels that it's showing and the colors and the legend shows data calculated based on a different denominator. In this

situation it's the installed future PV capacity divided by the gross minimum daytime load which is the gross DML that Anthony explained earlier about different methodologies to calculate. And the reason that that's important is because we want to be able to calculate a load on the feeder and use the load on the feeder, the gross load during the daytime period applicable to the timeframe when solar is at its most impact. So from the time that's 10:00 AM to 2:00 PM tends to be when most of our PV is at their maximum production or if on a day that it isn't producing then that's when we're going to exhibit our gross minimum daytime load conditions.

What we didn't want to do was to double count meaning we reduce it and then – we increase it in the numerator but then we also decrease it in the denominator. That would continue to – it would decrease our penetration or increase our penetration levels to the point that we're counting against the PV production online so we didn't want to do that and that's why we used the denominator of gross minimum daytime load. And what's highlighted in the box again is we have other threshold triggers within our interconnection study and it shows the gradation based on color level of the feeders that are over 100 percent and greater – and this map actually has been updated to show 120 percent of our circuit peaks on our websites on hawaiianelectric.com.

All our maps now show 120 percent and greater as a threshold for interconnection review. So the dark blue now is a trigger that shows 120 percent. So you can see that by that definition it means that the percentage of PV installed on the line is in some instances if it's dark blue is over our gross minimum daytime load conditions and they're fully at 120 percent so you can see where those locations are.

Slide 22:

As Anthony showed earlier these renewable watch screens are a way for us to communicate the conditions on the grid in your real time. It's updated probably on about a 15 minute lag and what you see in the dark line is really our demand on the system that we serve. The light blue is the reconstructed distributed PV generation overlaid on top of our load. It isn't the integrated load but it is the load overlay. It is the generation from the PV systems overlaid on

top of our system load so you do see the variability peaks and valleys from those generations.

And what we've done also to help our operators from a system perspective – and this is where distributed resources are now starting to impact the operations of the system and one of the regions, one of the reasons we show a regional breakout, north, south, east, west and central for our island is that the resource across the island also varies due to our complex terrain and our marine interactions. We have cloud formations that are very similar to the west coast with cloud formations and high terrain peaks. We have large volcanoes that basically create conditions of variability with clouds.

Another thing that we wanted to show was the profile from the day before. So you see on the lower right hand corner the yesterday profile and what you see here, it does track the net load on the system which is what we serve and then the reconstructed PV on top of net system load. And what we're noting here is that our system profile from day to day is not the same and so it gives our operators a sense of how they should plan ahead for their next operating day. In the past they've just been able to take the day before and say it's going to be here the same way. But what we're finding is that that's not the case anymore.

Slide 23:

So from a distribution planning impact there is a significant level of a lot of questions coming in, a lot of requests for net energy metering to connect to the grid and right now there is a threshold of stream that we're looking at is greater than 120 percent of DML. So up to 120 percent the maps have all been modified and reflect that change. We provide that visibility to the public, to the developers as well as our own internal staff because of the increasing levels of complexity for interconnection studies. And that will help us better communicate expectations on timing as well as what additional studies may be needed in order to support penetration at those high levels of feed ins and obviously if it's over 100 percent the condition of back feed which Anthony talked about and showed in the slide will have to be addressed. But on a condition where we don't have a lot of penetration on the feeder that condition will likely not be addressed so that kind of shows

people a sense of the level of complexity and additional studies needed depending on the penetration level.

So there's need to conduct these representative studies on the different types of feeders with different load characteristics. And we are actively and proactively changing our standards and our penetration policies to try to keep pace with the demand but our main priority is to maintain reliability on the grid making sure that what can be accommodated on the distribution in totality can be adequately protected on the system as penetration continues to increase because the aggregated impact of the distributed PV as Anthony mentioned is larger and get larger than our largest generator on the island that we do have control over so there is an impact. These distributed PV when they're all on on our system on our performance and our system operations for real time operations.

The field measurements are something that we're proactively pursuing and as I said before the irradiance data is going to be – we are actively working on getting the irradiance data coverage across all the islands across all our service territory at a very gridded resolution. It's something that supports – it's supported by our field sensors and it's measured so it's not just the modeled information database. And that will actually help provide a lot more granularity to a lot of these studies that we do related to feeders. The important point too is that a lot of the measurements need to come within that time period of 10:00 AM to 2:00 PM 'cause frankly trying to get gross daytime minimum load at nighttime is not going to really help us.

Slide 24:

So seeing and validating, this is another initiative that internally we've been proactively doing so that our operators, our planners get a better sense of what's happening on the grid in real time and as well they get a better foundation of the changes occurring on our system. Everybody talks about a paradigm shift in planning. Well it is shifting and we do see that the impact is a distributed using the tools like this, these visualization tools, we can see where it's impacting. So in this situation it shows that our – see that big load rise right in the middle of the day, right around 2:00. It's a 40 to 50 megawatt jump in load corresponding to a drop in PV conditions

that you can note from the sensors in the field. Without this information we wouldn't really understand or be able to explain what happened.

And we also have a forecasting algorithm. I think we're one of the first utilities to have an operational solar forecasting capability. You see on the right hand side the predicted cloud coverage across the island during that time and the irradiance on that scale at the bottom and that rainbow colored looking thing is in watts per meter squared. So this is a forecasting tool that we're integrating into our knowledge base and it's provided by – it gets its true power for the forecasting side. Here's an example of where the yesterday's data has no relationship to what we're seeing today and the situation is October 13th profile is provided. So here is another learning point for our operators and our planners that looking at yesterday's data may not be a good predictor of current conditions given the dynamics that we do see in our weather in our complex terrain.

Slide 25:

So a lot of new assessments are looking most at where there's integration needs between the distribution side and the transmission side from the system perspective. So trip settings, this is just a list of issues. We're not going to go into a lot more details on it but maybe we'll also revisit some of these in the interconnections in the standards but a lot of these things are going to impact our operations going forward. We've enacted trip settings that are a little bit lower than the normal 59.3 on the inverters. We have also under frequency load schemes that need to be revisited. We have to revisit our contingency plans, our reserve plans and there's a lot of work actually being done proactively by the utility to revisit and also to our system to accommodate a lot of the new generation and enhancements to the planning models that are being used to accurately model the system.

Slide 26:

Standards are also changing so in addition to us proactively looking at our conditions on the grid we're seeing that general industry is also seeing this need to really look at ways to better integrate the information and the performance of these distributed

PV and the behind the meter PV production – so our Triple EUL is manufactured inverters specifications being looked at by the manufacturers of the inverters as well as other battery storage options to complement some of the management needs to coordinate these resources.

Slide 27:

So this is just an illustration and gives people a sense of how quickly PV came on our system. Not saying that this is going to happen to you but it is something that you can see as over the years and this transition from 2010 so note the date on the side, now 2011, and now March 2012 and then the final one – one more click should be showing the December conditions of 2012. So you see the color change from almost nothing to mostly red and that greater than 15 percent which is our initial screening for the interconnection studies. This is why we needed to move to those orange and blue charts of ways of showing our penetration and also changing to this gross daytime minimum load calculation because with all of these things turning red our whole island would turn red and nobody would really have a good sense of what their needs are so we really needed to be able to provide that granularity and that's the changeover to those different maps.

Slide 28:

As we continue with our efforts we're continuing to monitor with field devices and also beginning to integrate a lot of this data into our EMS for operational awareness as well. So all this information our operators are already managing a lot of the coordination across our multiple generators and maintaining system balance. Now adding on 40,000 more distributed PV or behind the meter PV is really going to complicate their lives. So 300 megawatts of aggregated PV for them needs to be better incorporated and we're developing tools to co-op collaboration with DOE under SunShot program to integrate a lot of the distributed PV information on the ones we just went through, along with forecasting data so that it provides our operators automated resources to make informed decisions due to the impact of these changing – due to the impact of the variable distributed PV online and their changing conditions.

So we do have this distributed resource energy analysis and management system called DREEMS and we're developing that along with our EMS partners to incorporate into real time operations so the tools will provide some automation to help decision making by our operators that account for the impact of distributed PV changes across the system.

Slide 29:

Here are some example screens of the operators have given us perspective on as to what they think will be very helpful. And as you can see on the big island one, upper left side, our system operators there have sectionalized the islands to show how much generation per region is coming so that they can plan their system monitoring and other frequency load shed schemes and other things. The Siemens algorithm on our Oahu island, that's what we show the same regionalization so there's lessons learned from the first screen that was developed on the big island system by the Hawaiian Electric Light Company staff and then now we've actually incorporated sensors and monitors that show where we have monitoring devices as well as what the irradiance conditions are.

And this slide also incorporates the forecast so that the current hours, the zero hours indicates the current hours that the operations click the hour, the next hour, the two hour and then the next three hour forecast you would see on the system going forward in the day so you can see how the forecasted resource output for each region will be throughout the day. On the bottom slide is an example of how the data is also rendered in our Alstom EMS environment and shows the same systemalization, the color coding of the impacted PV at the various substations and then there's also additional screens where operators if they choose to want to dive into more details for say switching or other types of operations in that region they can actually look at the condition of those larger sub transmission lines to see how much PV may be on them, how much load is being served and if there's conditions of back feed.

Slide 30:

So, the DREAMS Initiative is just a little bit more, it talks about the EMS integration and as you can see the partners that we have

include a diversity of electric utility operators that use both the Siemens or the EMS, Siemens and also EMS systems. And our goal really is to begin integrating the forecasting data and the round statistics to help the operations of the grid. So the information that Anthony and his planning folks are developing really now gets impact, integrated into impacts on real time operations. And there's a utility advisory team that's comprised of these diverse utilities across the nation actually.

Slide 31:

We do –we are doing a lot of cutting edge, a new adaptations on our grid to accommodate all of the demands and interests by the public and our consumers and our repairs on our islands. The bottom line is we are really a launch pad of these technologies and they do need to be successful technologies with reliability criteria and standards and we are a great site to try some of these capabilities but we really do need to maintain the level of reliability in order to keep the lights on for everyone. So we don't want a failed experiment. We want to be the launch pad of a successful launch.

Slide 32:

And with that we're open for discussion. I think we're going to wait for questions later on. Turn it back to you Kristen.

[Speaker: Kristen Ardani]

Great! Thank you so much for that very informative presentation. I think we have a minute or two to take – maybe we'll take just one question in between each of the speakers. We have a question here for HECO. What is the length of a typical feeder line? That's kind of a broader question but maybe you could speak to some of the typical lengths that you encounter in your territory.

You want to take that.

[Speaker: Anthony Hong]

Yeah. Typical length of our feeder I'd say is normally within five miles I would say.

[Speaker: Kristen Ardani]

Ok. Great! Thank you! So with that maybe we'll hold the rest of the questions to the end so that we can get to Babak's presentation. And Babak if you're ready I'll go ahead and turn the floor over to you.

[Speaker: Babak Enayati]

Slide 33:

Sure. Thanks, Kristen! Hello everyone. So before I start my presentation of I would like to thank NREL for leading this NGIC program and also – and I'm sure this program is providing great benefits to the industry by creating a knowledge sharing forum. And also I would like to thank Kristen Ardani and Courtney Kendall for their great job in organizing these webinars.

So today I'm going to talk about how Massachusetts Technical Standards Review Group went through adapting the 100 percent minimum load screening for the supplement and review. I'm not sure if you're aware that this is a process that somewhere between expedited process and full impact study so that provides some cost and time benefits to the customers in the study phase.

And my contact information are out there on the website so feel free to contact me any time after this presentation. And one more thing, in my presentation there's links to the website. I know that the presentation will be available on the DGIC site and I know you can't really take notes but the sites will be available and you will have access to the links later on.

Slide 34:

Ok. We had a distributed generation (DG) working group in Massachusetts that was formed in sometime in 2013 and they actually – they were in charge of revising the connection tariff in Massachusetts. They addressed some new time lines for the interconnections and some technical issues and here's the link on the website. You can go through and read the reports but once that working group task is done basically one of the things that they all agreed to continue was assembling a working group called Technical Standards Review group. And it was this group that only focused on discussing the technical aspect of renewable energy in our connections and for our systems. And since then I've been

sharing this working group. It's a great group and on the next slide you'll see the website.

Slide 35:

And the goals of the Technical Standards Review Group are like basically we're discussing the technical issues with regards to interconnection but we want to, this group like we want to focus on the utility interconnection practices and guidelines and review them and try to increase the commonalities. Normal utility treats different technical challenges totally differently and the goal of this group is to like to create that forum place that everyone can come and share their knowledge and experience and come up with a solution that would make all the utilities in Massachusetts happy. And we've been doing a great job.

During the past year and a half we've changed, some of the utilities have changes their practices and the progress, you can go through and refer to our website and provide technical support for incoming interconnection challenges. Things change. Converters are getting, are becoming smarter. There's so many technologies that are being added to these renewable energy resources and so this group basically reviews these new technologies.

For example we had discussions about micro-grids, have discussions about smart inverters and we will continue this because we feel like the industry will and utilities will benefit from these discussions. And we actually try to make sure that the whole group understands it and understands the need for these new renewable energy resources and new advanced functionalities.

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And that's our website. You can go through that. We posted our meeting minutes and have some information about our membership and meetings. We always post the new announcements out there and we try to – and also there are other useful documents. For example like national grid interconnection guideline and there are other utilities that are actually working on their guidelines as well and those will be posted. It's a pretty good website. It's informative and you can get up to date on what's going on in Massachusetts with regard to interconnections. And with the membership we have myself leading, chairing the team,

and have folks from NSTAR with MECO and Unitil as utility members and the other non-utility members basically are representing the customers, government and the Massachusetts Department of Public Utilities.

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Ok. So after that quick introduction let's get into the major topic of this presentation. So the supplemental review process basically there are three screens and the first one is penetration screen of the minimum load. And second power and voltage screen and safety and reliability screen. In other words if an application fails the expedited or simplified process it's going to go through the supplemental review screen and if it passes all three screens it's going to stay in supplemental review process. And the difference between the supplemental review study compared to full impact study is time, the study time and the costs for the customer so basically provide like less costly and less timely study for the customers. So it kind of facilitates the interconnection process. It's good for both utilities and the customer as well.

Today I'm just going to focus on the penetration screen because that's the topic of the presentation. The other two screens, the GSRG group is working on those and we're trying to come up with a common guideline for our power quality and voltage and safety and reliability screens. That's an ongoing process and it's going to take a while but that's the goal to actually at least highlight some of the major concerns the utilities just look into when they do the power quality and safety screen.

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Ok. On November 22nd, 2013 FERC actually issued an order, order 792 and so they discussed basically different issues of interconnections but one of them was the minimum load screening for supplemental review. And I put the note out there but basically what they said was commission finds 100 percent minimum load screen is more appropriate for DG interconnections. Some companies file there with their concerns and basically their response was "well those concerns can be evaluated in the reliability and voltage and power quality screen."

And that's basically the guideline that we took in Massachusetts. We're looking at thorough analysis. We looked through that and we, basically what we did was we came up with our technical challenges which I'm going to go through on the next slide and decided to address some different screens and we moved the – we accepted the 100 percent minimum load screening and the good thing about this adoption is like for example if a customer from the dg application, if it's basically let's say 80 percent is the total distributed generation is 80 percent of the minimum load and it has really less impact or very minor impact on power quality and safety for protection.

If we say the lower minimum load screening for the supplemental review this project is going to fail the screening and then it's going to go to full impact study. Whereas by increasing it to 100 percent basically the project stays in the minimum load and supplemental review and we'll spend less time and money on the study which is good for us as a utility and the customer. And we're listing the order the FERC mentioned was the minimum load for solar generation. So we're not going to look into like 24 or basically they call it absolute minimum load for solar generation. We consider it as 10:00 AM to 4:00 PM for fixed channel systems and 8:00 AM to 6:00 PM for PVs that do have tracking system basically.

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All right so with that on March 13th, 2013 Mass Department of Public Utilities (DPU), also known as "Department" – so they directed the technical standards review group to actually look into this supplemental review screening and to gather some information from all the utilities plus we had discussions with other non-utility parties as well and I'd like to thank some organizations. They provided very meaningful information and we discussed those and basically DPU asked us to actually file our position back to them by February 28th, 2014 and we did that and this result was accepting 100 percent minimum load screen.

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Ok, so I'm going to go through some technical challenges that we discussed during this whole process which took almost a year and

how we addressed those technical challenges and how we were ok raising the minimum load screen to 100 percent. One of the concerns that the utilities had was maintaining the minimum load on the feeder section and that basically if they have a large business on a feeder section and for some reason the business shuts down on the owner decides to cut a portion of the business and the load drops drastically so that means the load goes down and now the aggregate generation is going to exceed the minimum load.

So that's a concern that these utilities had and also then we have feeder sections switching during storms and emergency switching procedures. Our dispatch center knows which sections can be switched and what feeder. Again that impacts the minimum load and which generator can be switched onto different feeder locations. Things like that we had very thorough discussions on that and we all agreed that this is basically a safety and reliability screen or a concern and then we decided to move all of these concerns to the safety and reliability screen.

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And when we moved the minimum load screen to 100 percent basically there were some issues with that with regards to protection and one of them was islanding, basically rotating generators can easily island if the load is close to generation for longer than two seconds. We're near like 100 percent match or a little bit less than that that the generators can stay on in the island modes for longer than two seconds. So that's a concern that we had and the reason for that is like these are rotating generators mostly do not have active anti-islanding protection so they're all passive meaning that they have some relays only to detect the island unlike the inverters where they try to protect the grid and detect the island through this active anti-islanding.

And also the inverters active anti-islanding protection may fail if there are large generators on the island and obviously I'm only talking about the minimum load and generation match and the reason for that is when the island forms inverter may see – if the generator is a enough of a large rotating generator it can actually hold three voltages up to a level that the inverter may kind of get confused. Is that voltage being maintained by the utility or another

device? So it may not detect the island within two seconds which is what's required by the suggested guidelines.

And also the Sandia report, I have also quoted the link here. You can read through that. It's very interesting report and so what they basically talk about like briefly I'll explain it. It's the total generation including any sort of DG – I'm sorry. Let me correct that. It's the total generation of inverter exceeds the 67 percent plus there's a one percent reactive VAR match that project needs to be studied. There may be a chance that an inverter by itself may island with the load. And obviously when we talk about 100 percent minimum loads, the 100 percent is larger than 67 percent so there's that 33 percent area that we may be concerned.

But the thing is like that 67 percent the island is a concern if the generation exceeds 67 percent plus you have 1 percent VAR match. So if you do not see any VAR match in the island even if the generation exceeds 67 percent inverters will be able to detect the island within two seconds without having any issues. And also Sandia report talks about how different inverters with different manufacturers when you have like multiple inverters form different manufacturers they can interact in detecting islands and actually the active anti-islanding detection may get desensitized because of this interaction and that's something to be looked at. They have a good flow chart that shows what type of inverters or how many inverters they recommend being the islands from different manufacturers. Plus they also address the inverter being in island with the rotating generator as well that I mentioned in item number two.

The fourth technical challenge with regards to protection is the impact on fault duty and coordination. Some feeder sections do have like heavy loads and that means like you can put more DG according to the screening so that may impact the fault duty at the end on our substations plus the protective devices may see some sort of miscoordination and that's not a big thing. That can be resolved by just really setting changes but in some cases these generators like may exceed the fault limit at the substation so that's something the utility will definitely need to look into and analyze in detail. And also the flexibility to deploy additional sectionalizing devices for reliability enhancement is something the utilities do very often. They install sectionalizing devices and when

you have 100 percent minimum load screen that kind of limits that flexibility if you only go through with that screen.

But in the end we realized that really this is not, this is not a kind of limit for the screening. This is a safety and reliability screen or safety and reliability concern so we decided to move that screen and so all these technical challenges that I talked about to the safety and reliability screen and stay with 100 percent for the minimum load screening.

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And the other challenge I would say like voltage regulations. When you have 100 percent it all depends on different factors that I'll go through but when you have 100 percent generation – generation that matches 100 percent minimum load especially for PV generation when you have intermittency on the feeder may impact the feeder section plus the entire feeder.

Well there are other factors to be considered in this whole analysis like distance to the substation. If you're closer to the substation the impact is less because that substation can hold the voltage and can stabilize voltage but as we go further down the feeder and then say like five mile feeder and you have a small intersection at the end of the feeder and you connect this large PV to that end you may see some voltage issues as the PC state and the entire circuit that you may see some issues with the system.

Things that you need to consider would be the feeder's assistance factor and the total load on the circuit as well. And also other power quality issues can be like the impact of DGM, the PCC voltage and power factors especially. Most of these inverters, not necessarily all but most of them right now like they operate close to the power factor so they're not generating that much of a reactive power so that means it's going to be less active power being pulled from the utility or the substation and if the reactive power demand is the same on the feeder the ratio of active or reactive power as you get closer to the utility may become less so that means you're going to have all of that. You're worsening the power factor at the substation. I mean closer to the substation.

And that's something that we've seen in some of our studies but again this is a power quality and voltage issue. It's really not a

screening issue. There are some projects, there's some inverters or any other types of DG that may create very minor impact on the voltage and power quality and also protection so we decided to actually move that and all these technical challenges to voltage and power quality screen to allow those small generators to pass through the first screening. I just mentioned this is a cost and time benefit for the utility and the customer. Ok.

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All right. With that I'll take a few questions.

[Speaker: Kristen Ardani]

Great. Thank you so much Babak. So we have a few questions that have come in from the participants on the call but for those of you on the line if you want to submit your question you can do so in the Q&A box on the go to webinar interface. So maybe some additional questions will come in but so here's a question for Babak. You mentioned that there is a potential time and cost savings associated with adoption of the 100 percent minimum load screen. Is there any estimate or do you have a sense for perhaps the number of projects or capacity that are now going through some type of cheaper or faster process instead of a detailed study? Is there a sense for the impact in terms of the number of projects that this change in the screening criteria has had or will have?

[Speaker: Babak Enayati]

Great question. I do not have the data right now but I remember when we actually had these discussions with the TSRG basically we had a six month window to actually monitor which projects would have gone through the supplemental review but they did not because this is just the first screening and plus like we also looked at the other two screens as well. It was not just the first but I think if I'm not mistaken in total we had like 15, something around that, for that 6 month period and – but after that I've seen, I've worked on too many supplemental reviews since then.

This is like the data that I'm giving you has been like I would say like seven, eight months outdated. Now I'm seeing more and more projects going through the supplemental review. The projects that I look at the load and generation match conditions and generation is

like 80 percent of the load and if you didn't move the screening to 100 percent it would have stayed in the full impact study but because we did that we see the good benefits with regards to time and cost. I apologize. I didn't have good data on that right now.

[Speaker: Kristen Ardani]

No. That's quite all right. I think that's a great answer. It's interesting to think about how the different screening procedures potentially impact the project timeline and cost for developers and also the time and cost that utilities spend doing these studies themselves. So let's see here. We have another question that's come in. So here we have a question that asks – although it's hard to decipher whether it's for HECO or TSRG but perhaps we can just pose the question to each of our presenters. It says that total harmonic distortion was not mentioned. Is it measured and is it believed that it is to become a problem with higher penetrations of distributed PV? So the question is about PHC. I don't know if either HECO or Babak would like to take that question but do either of you perceive a potential problem from that as we see more PV coming online?

[Speaker: Babak Enayati]

Yeah. I think and Anthony and Dora feel free to comment. But the thing is that the only requirement that right now we have on the PV is just the 519 which is a THG of less than five percent but as you add more PV generation there's going to be more harmonics on the system. I totally agree and that can actually impact that so basically – but that's something we'll look into in the voltage and power quality screening in order to understand how that – will there be any issues with regards to THG on the circuit but that doesn't impact the first screening. I'm not sure if that was a question for the screening but I'll let Anthony and Dora comment as well from their experience.

[Speaker: Anthony Hong]

I think in general we were looking for more quantifiable data to inform how we plan on screening for those 'cause right now it is part of the power quality assessment and as more information comes on about our penetration feeders it's something that we have to actively look at.

[Speaker: Kristen Ardani]

Great. Thank you. So we have a participant online who's asking Babak for a little more clarification in the screening process and how it relates to the supplemental review. I think this question is mostly directed toward the FERC order amendment and perhaps in the beginning of your presentation you briefly presented on well if you have these three different screens you get moved to a certain process. Could you just simply clarify in a sentence or two for the group how the screening process relates to whether or not you're moved on to supplemental review or not and how that's changed since the new FERC order?

[Speaker: Anthony Hong]

Sure. Absolutely. Great question. So I decided just to briefly explain that but I'm glad you brought it up. So when a project comes to the utility there's going to be different screenings according to the interconnection tariff. First it goes through the simplified process screening. Simplified is much less time. Basically we spend like a few days on that like very small and the impact on, the impact on the grid is very minor so we spend less time on that and the money, the study costs us less. There is like – if I'm not mistaken I think like 12 to 13 screening in Massachusetts for that and if a project fails any of these basically it goes to the next screening which is the supplemental review.

The supplemental review has, requires more time for the study but more money. It's going to be more costly for the customer and supplemental review has three screens that I mentioned a while ago so minimum load screening, voltage and power quality and safety and reliability. So if the project passes all three screens – so what it means is if utility, if engineer looks at the project and says "Ok so I feel like this project is small enough that there's not going to be that much impact on the feeder's voltage or power quality or plus protection and that impact is such that I can get it done at x amount of days I don't need the full time that we normally need for a full impact study.

And if we decide that's the case then the project stays in the supplemental review which requires less time compared to the full impact study. But if the project fails any of these three screens now

we need to do the full impact study. It's going to be a little bit more costly compared to the supplemental review plus the time. Obviously it's going to be more because the impacts on grid power quality and protection is much more.

But back to the point where how the impact of FERC order. Basically there was two different discussions going on between the utilities and some other organizations. Basically the discussion was ok, so we need to move that screening, the first screening to 100 percent because there will be some projects that will fail the first screen but pass the other two screens. Ok. And it's really not fair for that project to fail the supplementary review. Its impact on protection and power quality is very minor, it's something that can be done, can be studied within a few days. So we raised that and now that's what FERC also recommended as well. They realized any other concerns that we have can be moved to the other two screens. The first screen let's just focus on the minimum load screening. I hope I answered the question. I'm not sure if…

[Speaker: Kristen Ardani]

I think that was a great answer. I think it was just kind of speaking to sort of the basics of the screening versus supplemental review and then getting pushed into a detailed study so thank you so much for that. Ok. So I think we have time for just one last question and this question is for HECO. HECO how – for how long have you had the LMB map posted online for public consumption and since doing so have you noticed a change in the way that developers are submitting their applications or have you noticed any kind of helpful impact in making that data publicly available?

[Speaker: Dora Nakfuji]

Yes. The LBM maps were actually piloted back in 2010 under a California CSI grant initiative with Sacramento Municipal Utilities District, another high penetration PV program so that effort led to an automation upgrade to the results because it did attract some attention from other developers who thought it would be useful to get that information out. So the online search capability came online in 2012 and discussions with many of the developers and their recommendations. So we took their feedback and provided the information rendering it in a queriable database that also shows

the maps which then has the penetration thresholds which right now what we show is up to 100 percent but if you go to our maps on our www.hawaiielectric.com and look at locational value map or LVM you'll be able to see the updated maps that are updated every night for Oahu and again updated monthly for island of Maui, Molokai and Lanai as well as the big island of Hawaii.

And so since 2012 – actually since 2012 Oahu's online queriable version has been up online and again that took in feedback from the developers and the industry so what we've seen – actually when we first launched it we almost had a server crash because we had probably the second highest number of hits on our website for that particular screen so we had to do some enhancements to accommodate all the people using it. And since then it's a tool that I think we've gotten some good feedback on by users on our systems saying that it's good to get that information. We continue to support it.

We do see changes and we see more awareness of how quickly things are changing not only for our general public because now they have a way to look and see and verify that that circuit is very highly penetrated and it may likely result in additional interconnection studies necessary to look at different levels of concern or issues that may arise at higher officials or levels of penetration. But I think through that it's been more consistent in terms of communicating out to the public and sets an expectation that then we're not – this is a reality and so it's definitely a transparency issue.

I also wanted to mention that back in 2013 early quarter of 2013 a reliability standards working group initiative was set up by the Hawaii public utility commission to actually reassess the connection, interconnection process for Hawaii. And so a lot of that report and all that information is available on the Hawaii public utility commission's website and it's a reliability standards working group recommendations of SWG and in it you'll see that the locational value map and also the monitoring effort that we're doing that Anthony and I talked about were all things recommended that we continue to do and support and we've done that.

And also there's a proactive modeling effort that also advocated continued monitoring, prioritization, review and modeling and as Anthony mentioned in what they do within distribution planning. So we are revisiting our standards just as Babak is doing but we're also doing it with the Hawaii based stakeholders and the initial reports are available on the Hawaii public utility commission website.

[Speaker: Kristen Ardani]

Great. Thank you so much. Yeah. We've had a lot of prior discussions around impact of just making visual data available to developers so they get a better sense of what the potential queue might look like or what the process ahead of them, what they can expect, so I just want to thank all three of our speakers today for really helpful informative presentation and

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Also just remind folks that we have a monthly meeting. It's typically the last Wednesday of the month and that for next month will be on May 28th and we're going to have an event/webinar with WAFA as a co-organizer so it will be fun and cooperative and the topic will be enhanced modeling and monitoring tools for distributed PV interconnections following up on some of the data availability and visualization of data that can help the interconnection process from a cost intents perspective.

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So with that I just want to thank all of our presenters again, encourage you all to register for the next informational webinar and thank you for joining us today, appreciate your participation.

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