11-IEP-1G

DOCKET

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BEFORE THE

CALIFORNIA ENERGY COMMISSION

In the Matter of,	)
	)Docket Docket No. 11-IEP-
IEPR Committee Workshop on	) 1G, 11-IEP-1H
Distribution Infrastructure	)

Committee Workshop on Distribution Infrastructure

Challenges and Smart Grid Solutions to Advance 12,000

Megawatts of Distributed Generation

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

WEDNESDAY, JUNE 22, 2011

9:35 A.M.

Transcribed from a WebEx recording

Commissioners Present

Robert Weisenmiller PhD, Chair and Presiding Member, IEPR Committee
Karen Douglas, Associate Member, IEPR Committee
Carla J. Peterman, Presiding Member of Renewables Committee

Staff Present:

Paul Feist, Advisor to Karen Douglas
Jim Bartridge, Advisor to Carla Peterman
Kevin Barker, Advisor to Robert Weisenmiller
Suzanne Korosec, IEPR Lead
Linda Kelly, California Energy Commission
Michael Gravely, California Energy Commission
Rachel MacDonald, California Energy Commission

Also Present (*on phone)

Panelists

Christopher Villarreal, California Public Utilities Commission

Panel 1:
Jon Eric Thalman, Pacific Gas and Electric Company
Robert Sherick and Gary Holdsworth, Southern California Edison Company
Tom Bialek, San Diego Gas and Electric Company
Neil Millar, California Independent System Operator

Panel 2:
Frances Cleveland, Xanthus Consulting
Bob Yinger, Southern California Edison Company
Tom Bialek, San Diego Gas and Electric
*Ben Kroposki, National Renewable Energy Lab
Don Von Dollen, Electric Power Research Institute
*Brian Seal, Electric Power Research Institute
Jeff Berkheimer, Sacramento Municipal Utility District

Panel 3:
John Dennis, Los Angeles Department of Water and Power
Craig Kuennen, Glendale Water and Power
Jeff Berkheimer, Sacramento Municipal Utility District

Craig Lewis, California Clean Coalition
Timothy O'Connor, Environmental Defense Fund
Eugene Shlatz, Navigant Consulting
Alexandra (Sasha) von Meier, California Institute for Energy and Environment
Kurt Yeager, Galvin Electricity Initiative

Also present:

Gerald Bateson
Merwin Brown, CIEE
Dave Brown, Sacramento Municipal Utility District
*Barbara George
Frank Goodman, San Diego Gas & Electric
Jaclyn Marks, California Public Utilities Commission
Andrew McAlister, California Center for Sustainable Energy
Alan [Last name not announced], East Bay Power

I N D E X

I N D E X

P R O C E E D I N G S

JUNE 22, 2011 9:35 a.m.

CHAIRMAN WEISENMILLER: Good morning. Let's start the meeting.

MS. KOROSEC: All right. Good morning, everyone. I'm Suzanne Korosec, and I manage the Energy Commission's Integrated Energy Policy Report Unit. Welcome to today's workshop on Distribution on Infrastructure Challenges and Smart Grid Solutions to Advance the State's Distributed Energy Goals. This workshop's being conducted by the Energy Commission's Integrated Policy Report Committee.

Just a couple of quick housekeeping items before we get started. Restrooms are out in the atrium, through the double doors and to your left. We have a snack room on the second floor, at the top of the stairs, under the white awning. And if there's an emergency and we need to evacuate the building, please follow the staff outside to Roosevelt Park which is diagonal to the building, and wait there until we're told it's safe to return.

Today's workshop is being broadcast through our WebEx conferencing system, and parties need to be aware that it is being recorded. We'll make an audio recording available on our website a few days after the workshop, and a written transcript. However, we had a technical glitch this morning. Our Court Reporter called in sick so we're going to have to be relying on the WebEx recording for our written transcript. We would like you to be aware that each time you speak to please identify who's speaking since we don't have a person physically here to denote who's speaking at each point of the day. We will also be asking you during the public comment period to fill out the two comment cards that are available on the table out in the foyer with your name and affiliation so that we can make sure that those are reflected correctly in the transcript.

Also during the public comment period, please come up to the microphone at the center of the room so that we can make sure that the WebEx participants can hear you. And it's also helpful if you can give one of us your business card if you do come up to speak.

For WebEx participants, you can use either the chat or raised hand function to let our WebEx coordinator know that you have a question or comment and want to rely your question or open your line at the appropriate time. Those that are participating only by phone, we'll open the phone lines at the very end of the public comment period. We're accepting written comments on today's topic until July 6. And the notice for today's workshop, which is available on the table in the foyer, has the information on how to submit the information to the IEPR docket.

So briefly on how this fits into the Integrated Energy Policy Report, the Energy Commission is required to prepare an IEPR every two years that includes assessments of things like energy supplies, demands, price, transmission, distribution and provides recommendation for energy policy forward. This year a critical element of the IEPR is the Governor Brown's Clean Energy Jobs Plan. Among other things, that plan calls for building 12,000 megawatts of localized electricity generation and 8,000 megawatts of large scale energy renewables and necessary transmission lines by 2020 and also developing energy storage to reduce the need for peaker plants and out-of-state coal imports and to help firm up renewables.

As directed by the Governor's Plan the Energy Commission is preparing a renewable energy strategic plan as part of the IEPR. This will identify challenges to meeting our renewable energy goals and to provide suggested strategies to address those challenges. We anticipate releasing the first draft of that report at the end of August and holding an IEPR Committee Workshop on September 14 to get public comments. Obviously, distribution level integration is going to be one of the major challenges that will be covered in the renewable strategic plan. Our electric distribution system is the largest element of the overall electric system but it wasn’t designed to accommodate the amount of renewables that are envisioned in the state’s policy goals. We’ll need to be modernizing our aging distribution system using new distribution automation and smart grid technologies to improve power quality and reliability, develop uniform standards and cyber security measures and coordinate distribution and transmission system planning. Our agenda today begins with comments by the CPUC, followed by two panels this morning. The first covering the Investor and Utility Plan for interconnecting and integrating 12,000 MWs of DG and the second covering inverter function to support the management of increased DG in storage in the state’s distribution system. We’ll next have a presentation from the Galvin Electricity Initiative on DG Infrastructure and Solutions and then we’ll break for lunch hopefully around 12:15.

In the afternoon, we’ll reconvene with a panel on publicly owned utility perspective and strategies. Next, we’ll have a presentation from the Environmental Defense Fund on assessing smart grid investments to benefit customers and the environment followed by a discussion of how R&D can help advance DG. We'll then hear from the California Clean Coalition about strategies for grid connections and from Navigant Consulting on possible solutions and tradeoffs involved with distribution system upgrades. We'll finish up the day with an opportunity for public comment. We have a very full agenda so I won't talk very much longer and I'll turn it over to the Chair for opening remarks.

CHAIRMAN WEISENMILLER: I'd like to thank everyone for their participation today. Obviously, I think, we're bringing together two interesting and important topics and, as Suzanne said, we have a pretty packed agenda so I'd just assumed we start.

MS. KOROSEC: All right. I'll turn it over to Linda Kelly, our distribution guru, and she'll take us through the workshop.

MS. KELLY: As Suzanne said we have a full agenda so I'll just go right into the agenda. Our first presenter will be Christopher Villarreal from the CPUC and he's going to give us an update on the smart grid proceeding at the CPUC. Chris is a Regulatory Analyst in the Policy and Planning Division of the California Public Utilities Commission. He is a staff team lead on the CPUC's smart grid proceeding. Chris has been instrumental in helping the CPUC develop policies related to smart grid deployment plans, privacy, third-party access and cyber security. In addition, Chris has been involved as part of our Commission Staff on a number of other issues including demand response and dynamic planning. Chris?

MR. VILLARREAL: Good morning. I'm Chris Villarreal with the California PUC. I want to thank Chairman Weisenmiller and the CPUC for inviting me to participate this morning. As Linda said, I'm just going to be giving a relatively short overview of where the CPUC is at on their ongoing OIR. The first couple of slides are mainly for—I don't need to go over them. I've presented on them to you before, last December, so they're largely here for historical purposes. I'll just skip right on over to the deployment plan.

As you may remember, the legislature in 2010 passed SB 17 which directed the PUC to develop a requirement for a smart grid deployment plan. In June of last year we issued a decision. The decision said that the deployment plans must address eight topics: smart grid vision, a baseline strategy, grid security and cyber security strategy, smart grid roadmap, cost estimates, benefits estimates and metrics. The deployment plans are due to be filed by July 1 of this year.

San Diego came in well ahead of the deadline. They filed theirs with the PUC on June 6. The deployment plan was organized by the eight topic areas but identified within the eight topic areas, nine program areas. And I’m going to spend a little bit of time talking about San Diego.

So the nine areas that they identified for their deployment plan is customer empowerment, that includes providing customers with additional information, how to help customers make more use of the information that we made available to them from the near home area network and other tools. The second one is renewable growth which includes integrating renewables to make an impact of the renewables on the grid partly, I imagine, that some of this will be discussed today. Electric vehicle growth is very similar to renewables, how to mitigate the impacts of electric vehicles on the distribution grid. Reliability and safety, some of the programs that they’ve identified are advanced measuring and identification technologies including VAR dynamic ratings and voltage ratings. Again, this is to help as more technology information is available down on the distribution grid, this information will help San Diego plan better for the future. Security, operational deficiency, There are such things as arc detection for fire prevention, smart grid RD&D. One of the examples of that is funding for microgrid projects. Integrating cost cutting systems deals with communications infrastructure and other technologies that cut across, not just simply energy but on the communications side. And workforce development. As I think many of us are aware, the workforce is beginning to age a little bit and the utilities as well as the PUC have to deal with increasing amounts of retirements coming up, so how do we bring the workforce up to speed and how do we encourage more workforce to take over the openings.

This is a list of cost and benefits. I threw this up here because it’s nice to see the numbers. What I’ll point out is that those are five and ten year estimates and provisional numbers. The estimated cost of $3.5-3.6 billion to do all the programs that they’ve identified with estimated benefits of $3.8-7.1 billion. So those numbers are, obviously, dependent upon the technology, how the market develops, whether or not things can be—if cost can come down in the future. This is just a snapshot of where we are today, June 22, 2011, and what might be possible ten years from now. So I think we want the cost and benefits but we also want to appreciate that these numbers are very fluid because it’s unclear what technology will bring in the coming years.

So, what are we going to do next? As I said, the deployment plan for Edison and PG&E are due by July 1. I suspect that we’ll get them right around July 1. What we plan to do is, in coordination with the CPUC and the ISO, we’ll hold a series of workshops to review the deployment plan, for the reasonableness – whatever reasonableness that they mean, and then to ensure some consistency across the deployment plans. I suspect the workshop will be held throughout the year and into the beginning part of next year. And just a reminder that an approval of the deployment plan does not mean cost recovery. Cost recovery and approval to a specific program will still need to be done through the general rate case or through a separate application. San Diego and Edison are both in the middle, beginning to middle, of their GRC phase right now. San Diego recently issued a notice to the GRC Service list that they’re going to have a public meeting to discuss how the deployment plan integrates with their existing GRC.

So I can’t do a status update without talking about private and third party access proposed decisions. That’s not necessarily on the topic of this discussion for this workshop but I think it’s part of the status update. So the PUC issued our privacy and third party access for proposed decision on May 6. Initial comments were filed on June 2. We got 25 commentors and reply comments were filed on June 8. The major item from the proposed decision are that it implements SB 1476 on privacy and security requirements and utilities, it aligns California with the Fair Information Practice Principles which are the basis for a number of federal privacy statutes and rules. It directs the utilities to provide additional information and tools to customers to better manage usage. It proposes that pilots provide prices in near real-time. That does not mean real-time pricing programs. It just means providing the price of electricity to customers in as near real-time as possible. It proposes a pilot to provide customers to connect devices to the meter through the home area network. It requires the utility to notify the PUC upon a security breach affecting 1,000 or more of their customers. And it would initiate a new phase of the rulemaking to determine applicability of the privacy rules upon gas companies, electric service providers and community choice aggregators.

I suspect, and I hope, that this decision will likely not be voted out of our Commission meeting next week. I'm hoping that it will be voted out at our first meeting in July, on July 14. So that is basically the status of where we are. I'd be happy to answer any questions that you may have.

CHAIRMAN WEISENMILLER: Thank you very much for being here and for your presentation. And we appreciate CPUC's participation in this proceeding. I guess a couple of questions that I have are that as SDG&E deployment plan numbers. My impression is that they included the smart meters that have been rolled out, is that correct?

MR. VILLARREAL: The benefits may have—I believe the benefits did but the costs, since they were already approved, would not be new additional costs they would be existing baseline costs.

CHAIRMAN WEISENMILLER: Okay. That's good clarification. And the other question that I had. One of the issues on the smart meter rollout has been, whether the good or bad news, has been consistency across the utilities. So in terms of the smart grid, again, I was wondering how you would try to deal with having three individual applications and encouraging experimentation but at the same time trying to have enough consistency so that, let's say, the Cal ISO is more of a single type of interface.

MR. VILLARREAL: Well, procedurally, the first thing we'll do is we consolidate the three applications so that we'll have one judge, one set of staff and one assigned commission that is flipping the various applications across the Commission. By consolidating them we'll be able to have a series of coordinator workshops where CPUC staff and ISO staff will be able to participate directly with development of the deployment plan. How we then approve the deployment plans and what that actually end up meaning, I believe, is still to be determined. Again the deployment plans are not approving costs and programs. So the end result will still be this is the plan, this is an approved plan, but you still have to get money funded through the GRC. That's just what our thinking is right now. As we get our other two deployment plans in and as we start working through the workshop that strategy may change. We may find a better way to do this but for now that's the idea that we have.

CHAIRMAN WEISENMILLER: That's good. The last question that I have is obviously one of the things that we're dealing with on the distribution system is a lot of it is circa 1950s vintage and so to some extent the smart grid is both the replacement and the modernization. Do you have a sense of if the San Diego part what the split is between the replacement and modernization?

MR. VILLARREAL: I do not at this time. Tom Bialek is here and when it’s time for his panel, I’m sure you could ask him that asks and he’d have a much better answer than I could. What I will say is that the deployment plan, which I happen to have right here, is right around 300 pages and in that 300 pages there is a lot of specificity but I think it could still be more specific and that is something that we’ll continue to address over the upcoming months is to get the more specifics out of this thing through data requests or through workshops with the utilities to really be able to answer that question, that exact question, you asked.

CHAIRMAN WEISENMILLER: Thank you very much.

MS. KELLY: The next item on our agenda is a panel. And this panel is looking at Planning for interconnecting and integrating 12,000 MWs of DG into the Distribution System. And we’ve invited the three investor-owned utilities to participate in this panel as well as the ISO. This afternoon we’re going to talk with the POUs and ask them a lot of similar questions.

But what all distribution systems have in common in California is that they were carefully developed and engineered to deliver one way power from central station down to the transmission system substation customer. Today these same utilities are being asked to engineer and update this system with the new California goals. This panel has been asked to individually discuss how, in the next 1-5 years, they're going to plan to deal with aging infrastructure, managing interconnecting hundreds of distributed generation projects on the customer side of the meter and evaluating determining what smart grid technologies they should integrate and when they should integrate them.

Traditionally, planning for transmission, distribution and generation has been done in isolation. But just as the one way power grid that we all use and enjoy today is outdated and becoming outdated, this paradigm of planning in isolation is also outdated. Part of the panel will be to discuss how the planning for the future and raise issues and discussions on how to better coordinate that planning as we go forward to achieve those goals of the state.

I think that what I'd like the panel to do is that I'll introduce you one at a time and you can just come up and make your presentation and then go back to the table and when we're concluded we'll ask questions of the panel. First, some additional questions I have and then open it for the public.

The first person on the panel that we're going to start with, we're going to start on the North. We're going to start with PG&E and this gentleman's name is Jon Eric Thalman and he is a Director of Regulatory Strategy and Support at PG&E. His department supports PG&E's Transmission Owner and General Rate Case Regulatory Filing and supports strategy and policy development for new electric transmission and distribution technologies. Mr. Thalman?

MR. THALMAN: Thank, Linda and good morning Commissioners. I'd just like to say that in preparing these remarks we've endeavored to address specifically the questions that were outlined in the agenda and were asked specifically of us and these were broken into three categories. These are planning for the future, what our future plans are, specifically looking at interconnecting DG resources to the distribution system and also how we're incorporating our smart grid goals and our environmental goals into that overall effort.

Starting from the top with the planning. Our focus with planning for the distribution system around reliability and flexibility and operational control. It takes many different players modernizing, looking at installing advanced automation and monitoring control technology, focusing our capital investments on installing new tools that can improve the performance from a reliability perspective and from the maintenance perspective. Also using condition based maintenance practices to know when to best make the upgrades and to avoid outages from component failures and also improving human performance just as we execute the work.

As was mentioned, a lot of our infrastructure was installed back in the 50s and earlier in the two decades surrounding that. We have an ongoing program to address that. These details are outlined in our GRC but they follow a standard category of substation breakers, wood poles and cable replacements. We're moving forward with that as we expand the smart grid capabilities of the distribution system with automation and control schemes and also being able to draw more information back so that we know more of what's going on so that instead of a passive grid, a distribution grid, it's active and knowledgeable, controlled and up-to-date in monitoring the grid.

Some of the challenges as we look at high-levels of DG penetration, of course, and these are topics that I'm sure we'll talk at great length today as we move through the different panels and presenters is maintain service voltages within appropriate limits, dealing with voltage transits for a variety of different reasons whether it be renewable intermittency or changing loads, integrating all of this into system operations. How do you now manage a distribution system that was once a one way feeder operation to a two way more of a network? A lot of work has been done around forecasting measures and we're looking at that also. If you're going to have intermittency is there a way to looking ahead of that. I know that the ISO is looking at that.

I mentioned earlier monitoring the control which is an important aspect as you need to have your infrastructure to be able to accomplish those capabilities. And then also these are kind of presented in order of priority from a PG&E perspective. There's also potential for inadvertent islanding. There are appropriate safeguards for that right now but as we go forward and the grid is evolving that is something that we need to address and look at when it would be appropriate.

So some of the specific things we're doing to look at pilots in some of these areas that will help up accommodate more DG are some pilots. We have a demand response pilot with the ISO to look at adjusting loads and participating in ISO markets to be able go firm resources for renewables. We have some, two actually, battery storage projects. One of them is going to be operational this fall, a two megawatt system out of Vaca-Dixon, that will be looking at mitigating distribution system impact and also helping to integrate local PV resources in that area.

And then, finally, as part of our smart grid plan which will be filed later this month before the July 1 deadline by the CPUC, we’re proposing to look at some testing of voltage control systems or volt VAR optimization tools. This will be in a laboratory and in a pilot environment to see how these might perform on a distribution feeder to help control voltage as well as higher penetration levels of DG.

So some of the existing tools and new tools we’re looking for in distribution planning, or our toolbox, if you will. We’re just rolling out a new load tool program this year that helps our distribution planners to model more accurately distributed generation resources and new loads and new types of loads. This program we’re integrating our planning and operation functions this year and next year. We also use a more robust planning tool that’s used more on the transmission side than the distribution side for modeling interconnections and distributed resources that are under the ISO control. This allows us to analyze the impacts and look at what appropriate updates will be needed for reliability. And then finally in our generation interconnection services we're continuing to look at how to handle the increased level of interconnection requests and to be more effective and efficient in processing those and being more accurate through this database tool we're using to track all of these interconnection requests, thousands and thousands of interconnection requests, and ways in which to aggregate those so that we can better assess the system impacts and know what's going on and what's the plan on their end.

This is to shed some context on our interconnection process. The planning process that we look at to interconnect loads and distributed generators has some important aspects that we feel are vital to go forward with the changing face of volt meters. For both new loads and new customers and load growth we look at each one of these on an individual basis for their potential for increasing the—for the need to increase the capacity on the distribution system. So factors such as location, load, service voltage, service point – each one of these needs to be looked at individually while all at the same time keeping accuracy of the process and even being expeditious about it.

On the flip side, looking at new distributed generation resources. You also need to look at each resource based upon its circumstances. For both of these we followed similar principles all the while trying to increase and improve the efficiency and accuracy of the study but do it quickly and in a timely manner.

Inevitably, and I'm sure Neil will probably touch on this from an ISO perspective, as the amount of distributed generated resources increases it has a bigger impact on the ISO operation. So there's a need for, even at the distribution level, there's a need for coordinating with the ISO. So for large amounts of proposed distribution resource pockets and also transmission connected, there's certain areas where this begins to have a substantial impact on ISO control. Some examples of that are in Fresno and Bakersfield where we're seeing large amounts of distributed resources being proposed and coordination with the ISO is appropriate there. Also the ISO has a responsibility to perform the deliverability assessment as part of the resource adequacy program from the CPUC and to the extent that this has an impact, the ISO needs to be involved. And then also, again, the ISO needs to be involved due to the scheduling—involved in the scheduling items over one megawatt so we need to be coordinated with them.

So further points on interconnecting distributed resources to the distribution system. We feel that it is unnecessary to coordinate distribution studies on a statewide basis. We feel that that would be an unnecessary step. For example, for PG&E service territory it’s generally not important to coordinate what’s going on in Stockton with what’s going on in Fresno. So you don’t need to have an overarching statewide plan. You can look at these on a local basis. Some suggestions we’d like to provide on some process improvements on your connection study. I think a lot can be done to educate developers and utilities on the process. We find ourselves answering a lot of questions and asking a lot of questions and trying to gain clarity about what the developers’ expectations are, what the rules are and helping them understand what the rules are from a utility perspective.

I think there could be some further work done on coordinating the procurement programs such as feed-in tariff; we have renewable auction mechanism and then the interconnection process. Some of those could be better coordinated.

Also, there’s a need for, tying back to the first point on educating for the risk of using a loaded word such as transparency, around some of the market rules. For example power purchasing agreements, interconnection rules and timelines, planning an interconnection group having to answer a lot of questions about purchase agreements. Well, that's not their role. In fact they shouldn't answer that question. That's the energy procurement side. A lot of education for developers to understand, "Yeah, you're understanding to PG&E but you shouldn't ask the interconnection folks about your power purchase agreement." That puts them in an awkward position.

We also believe that looking to pre-identify sites could be helpful. We realize that developers are kind of shooting in the dark sometimes and to do some kind of pre-screen to identify needed areas and helpful needed areas would be helpful. And then also when you look at the queues, the interconnection queues, there's projects that have been there for years and, not that it doesn't take time to develop projects and there's lots of hurdles and we want to mitigate those, but perhaps there needs to be a policy where we can help minimize the queue by sun setting some projects when they're no longer viable as there are some hurdles that people have to continue to – that developers have to meet in order to stay in the queue.

So touching on the third section, some of our smart grid and environmental goals that we’re working towards, there was a question on what air projects we’re involved with. Here’s two who were a sub recipient of a WDAT grant on the synchrophasor project, there’s a matching portion of that as part of a much larger part effort on the Western United States. There’s also compressed energy storage project. We’re looking at a feasibility study and initial environmental reviews to look at a 300 megawatt compressed air energy storage project down in the Kern County area that’s conveniently located with a lot of renewable wind resources and solar resources in that area. There’s matching and PG&E funds for that also.

If that proves to be feasible and cost-effective then PG&E would go to the next step and issue a competitive solicitation and go to the next phase on that.

Some of the other things we’re working on, and these are technologies in our general rate case that we filed in 2011 or we’re finishing in 2011, excuse me, our smart grid activity has been worked into our historical level of spending so what that implies is the maintenance work and replacement work that we’re doing.

We’re just going in and replacing it with updated equipment for the smart grid. In addition to that we included $66 million in our—from 2011-2013 on the capital extension forecast for some foundational smart grid deployment component.

And a lot of these are focused on information and IQ type of connecting, bringing the data so that you have the visibility of what’s out there in the distribution system. A lot of these are focused on this type of component. The actual—a lot of the actual switching and kind of devices that was used to gather the information seems kind of the next wave.

Finally, some of this compliments that I mentioned as some of the next wave. These technologies and software—some of the three of these that we’re looking at, and I mentioned these earlier, the volt VAR optimization technology, we’re looking at that pilot. Once we gain some more security on that then we’ll look to move forward in those areas, if it looks viable. We think that that is an area that has promise when you’re looking at the issue of controlling voltage on the feeder when you have a large penetration of resources out there. We’re also looking at leveraging the capabilities in the smart meters in our area to see how those might be helped—might be a help to the distribution resources in the areas where there are smart meters. And then also, looking to team with inverter manufacturers. We have some studies going with them to examine ways that the new inverters might be able to convert—communicate with the new control system in the distribution system. Just to list that as an example, if you have a voltage problem out on a feeder you might look to employ some type of device like a volt VAR controller or a capacitor or an energy storage device or whatever would be the most appropriate, but you'd have inverters that would control—four quadrant control inverters that might be able to control the megawatt and mega VAR flows and control the voltage. We'd like to look at what would be the viability of involving those in that control using them as part of the grid.

So just in summary on this, we've taken somewhat of a conservative approach in calculating the economic benefits of these. This is more of a pilot methodology. We're looking at it and looking at the economics. We have endeavored to quantify some of the CO2 reductions for some of these but we haven't really penciled those in as a financial benefit in our filings. I think that's the end of my presentation. Thank you.

CHAIRMAN WEISENMILLER: Thank you, very much.

Very interesting presentation. A couple of questions. As the first speaker, you'll probably get more than your fair share. The first one is probably a good opportunity for you to talk about how this plan reflects lessons learned that PG&E got from its smart meter rollout experience.

MR. THALMAN: There's many lessons learned from smart meter. I think one of them—I mean the biggest lesson from smart meter is communication with its customers, I believe. The technology issues and the rollout were appropriate and expeditious but it's communicating to your customers and if you bring more tools down to the customer level as more as the operation and control of the systems is brought down to the customer level then we believe it's more important for them to understand what's going on with us. For example, our customers are installing renewables on their—say they're going to put PV on their rooftop or there's something going on in their community level, it's important to communicate with customers so those messages don't get sideways so they see this as an advantage and an improvement in their energy usage and delivery.

COMMISSIONER PETERMAN: A follow up question to that Jon. The technology infrastructure upgrades that you mentioned focus in the areas of information exchange, data management and data storage that are part of the GRC. Once you do those, do those require new meters to be installed? To then be compatible?

MR. THALMAN: Ideally it would not. We're not looking to have to install meters. But that's somewhat constrained what you're looking at but if you're building from the ground up with a foundation of devices that will collect the state information versus the meter and an information system that will communicate that and aggregate it and then next you have the devices that will use that for moving that which we believe is a natural way to progress, you do narrow your options, obviously. But we believe that that's a natural way to progress – that you start with collecting the data and bringing it together and then the right equipment to utilize that.

COMMISSIONER PETERMAN: So this is the bringing it together upgrades that we should expect? These upgrades would bring it up a level?

MR. THALMAN: Yeah. Well, as I mentioned in the briefing three slides ago we're mostly working on right now is the information systems to bring this together. So a lot of our smart grid improvement and I think this will be a lot of what you'll see is what we'll file with the CPUC in a couple of weeks, or 10 days, is that IT will bring this together and then the devices – there'll be some devices that will be on pilot level and they'll roll out on a pilot level that will come as you go through and do maintenance on the system and replace those devices.

CHAIRMAN WEISENMILLER: I guess a similar question was to ask you to describe you how PG&E has taken the lessons learned from the San Bruno experience, like the expert panel, in terms of its thinking with the smart grid.

MR. THALMAN: There are a lot of things pointed out in that report. Are there any in particular that you'd like me to address?

CHAIRMAN WEISENMILLER: Well, I think certainly in terms of the questions on process or management of a focus but the safety focus. But I guess one of the questions is how can this help us be comfortable on safety issues. I'm sure this may be the first time but probably not the last time people have asked you how the lessons learned from that are affecting your smart grid operation in general.

MR. THALMAN: Safety continues to be an important priority at PG&E and that's no exception on the distribution system. Our policies on islanding protection requirements reflect that. By building in this manner, by looking to bring the data together and do pilots with testing out these devices before just going out and installing them. I think that’s a prudent way of progressing so that you can test and you can know before you put these things in your neighborhood. Not that there’s any glaring problem with a volt VAR device but you don’t want to cause an outage in an area where a volt VAR device isn’t coordinating with something else or we haven’t thought through all the ways that the volt VAR device would work with the control system or a group of inverters for solar panels in residential theater.

CHAIRMAN WEISENMILLER: At this point is there any consensus or evolving consensus on what are the best practices for dealing with interconnection at the distribution system?

MR. THALMAN: I think that that’s an interesting—I don’t know that there is a consensus. I think that at PG&E we feel that there is some guiding principles that need to be followed and that is that while we do want to not hold up progress and move in this direction, you don’t want to get—to do interconnection studies where you’ve applied a broad brush in a general formula and you didn’t look at the important details to an interconnection and then find that you have a problem in that area and you've having to go back to the developers and the expense of working with developers and trying to resolve things is that the customer might suffer; especially if you get to the point where you get something installed and it's causing problems. So we think that—there's not really a consensus. I think that that's one of the important things that in this workshop and advisably other workshops need to address. The question is what is the best way to look at the interconnection process.

CHAIRMAN WEISENMILLER: And I know you're still working on smart grid filing but I'm trying to get a sense of the magnitude between the replacement cost and the smart grid cost in terms of—is it an extra 50 percent or 100 percent?

MR. THALMAN: I don't have that right now. We can try to provide that.

CHAIRMAN WEISENMILLER: Okay. That'll be good. And I guess the last question for you. PG&E, I'm gonna say, is probably at 204 in its general rate case. After one of the recent storm induced outages and the Commission ordered a filing to look at reliability of service and throughout the various parts of your service area territory. And as we look at sort of DG rollout, I was trying to figure out how far people have thought about either reliability of benefits to resource adequacy benefits to be targets of certain areas. Again, I know we remember the statistics generally well, but obviously as you're going up into the Santa Cruz Mountains I think in every storm you lose lots of power in those areas. And certainly up in the north coast area too, I mean there are areas where the winter storms come in and the distribution—which will result in transmission distribution losses and outages and trying to figure out how DG might be part of helping solve some of those issues.

MR. THALMAN: Well, currently, the safe and prudent way to progress with DG is when you're dealing with, and I think what we're getting at is the ability to island an area, that's a far more complex problem than the level of DG we're putting into an area plus there's significant safety concerns. You can imagine the Santa Cruz Mountains you're sending employees up to work on lines but yet they need to know who has sufficient DG in the area and what little island might still be working. I think that safety being paramount that that needs to be looked at clearly before we can go ahead and allow that scenario. Granted, there's some upside to being able to get people's power on if you can island an area but we feel that the safety concerns outweighs that need. Granted, keeping the power on is also a safety concern but having crews out working and not knowing which lines are live and which ones are not I think would be important. But the other comment with smart grids is that the information that is gathered, the switches and other automated devices that would allow power to be established quicker, you don’t have to roll trucks and crews and—we believe that that actually has a bigger upside to restoration after a storm or a large event in an area. You’re not relying on people calling in, you’ve got the instant map from the smart meter data of who’s on or who’s not and you know exactly where the problems are. In addition to that, the operators looking at that, you also have automated schemes and those are some of those that we’re piloting for the smart grid that would automatically detect and energize appropriate sections and then isolate other sections so that crews can go out and work on those.

COMMISSIONER PETERMAN: Jon, one last question. One slide 10, Interconnecting DG to the Distribution System, under suggestions for process improvements. Could you expand more on coordinating procurement programs in particular what aspect of coordination would be most important, is it timing or?

MR. THALMAN: I’d be guessing to be honest with you.

COMMISSIONER PETERMAN: Pardon?

MR. THALMAN: I'd be guessing on the coordination issues there. I was asked to raise that as a bullet point. And we can elaborate on that further if you'd like.

COMMISSIONER PETERMAN: As an overarching point then?

MR. THALMAN: Yeah.

COMMISSIONER PETERMAN: I'll keep it in mind.

CHAIRMAN WEISENMILLER: Thank you.

MR. THALMAN: Thank you.

MS. KELLY: The next member of the panel is Robert Sherick from Southern California Edison and at the table he's also joined by Gary Holdsworth, I don't know where Gary's title is but I have seen him at all the interconnection processes that the ISO and for Southern California Edison so he's definitely an expert on interconnection so I encourage you to ask him any questions in that particular area but Mr. Sherick will talk—he's from the Advanced Technology and Distribution Transmission Business Unit and he's going to talk about planning for Southern California Edison and smart grid solutions for the future.

MR. SHERICK: Thank you. Good morning. Thank you for allowing Southern California Edison to address these questions on distributed generation and to lend to its points I will be talking about planning for the future and our deployment plan and yes please direct the interconnection questions to Gary who is our expert on that and I'm sure that he would very much enjoy the discussion in-depth on that subject. So I'll be briefly addressing the questions from the first and third sections and Gary will be addressing the questions from the second section.

So there's a question on the overall vision on the distribution for Southern California Edison and this is our overall transmission distribution vision. We think it includes both the transmission areas and the distribution areas very well. We've talked a lot about safety and continue to talk about safety. Just a couple of days ago we had an instance with one of our personnel in one of our substations. It is an ongoing concern and PG&E talked about the islanding issue. We're very concerned about that and believe that as long as we have some sufficient rules and understanding we can make that an issue where it will be done safely. Comply with the rules. This is both compliance and sort of safety and reliability as well as the environmental policies in the state of California. Keep the lights on. We've talked a lot about the aging infrastructure. Really if you look at Southern California and the growth of Southern California in the post-war years, a lot of our infrastructure was built in the 50s and 60s and a lot of that infrastructure needs to be replaced.

As we build a smart grid, we definitely need to have the infrastructure behind it that's going to be able to accommodate new control systems and new voltage VAR operating systems as well.

Satisfy our customers. A lot of this has to do with, obviously, interacting and engaging our customers. A lot of this has to do with being an effective and efficient utility for interconnections to come on to the system, being able to apply the devices to the system.

Spend wisely. That is pretty obviously a wise goal of ours going forward.

And build for the future. Really looking to enable the utility to be around for another 125 years so we are looking to safely and efficiently integrate centralized and distributed renewable generation into our system. When it comes to vision, when you've been in business for 125 years, we are now hitting our 125th anniversary; safe, reliable, clean and cost effective energy in Southern California is what we're trying to do. That clean component is certainly new. It’s probably only been there the last 30 years of our history. And then there was a question concerning how do we integrate all of this and, really, through the general rate case one of the nice things is that every three years, we have to get up in a public forum and explain what we’re doing, explain what the costs are, explain why they’re doing the expenditures that they’re suggesting and we have a very good opportunity to integrate both our existing infrastructure with those activities that we’re looking for in the future.

Concerning the ARRA investment opportunities, we have two very large programs that we’re the lead on. One is the Irvine Smart Grid Demonstration Program, I’ll talk a little bit more in detail about this program since it does have a good deal to do with distributed generation storage. This is divided up into several subprojects; the subprojects that I’ve got listed are more applicable to today’s conversation.

Zero net energy home, a goal of the state’s by 2020 for all new residential homes. We are looking at how that might be done, what are some of the impacts of that, how that would be managed. We have some—two feeders in our distribution circuit and applying some technology to a set of homes that will include both solar panels and storage in the homes and be able to take a look at how the customers may operate that DG storage and how we might operate that DG storage and be able to make some comparisons. This includes the communications that you go and give the customers and to see how you can incentivize them, to use them in an optimal way. Also, plug in electric vehicles, both at the home and work, so we're going to be setting up some electric vehicle charging stations in the home as well as at a parking lot in nearby parking Irvine Campus and be able to see how that would be able to work and interact with some distributed generation on the rooftop at that particular parking lot.

Community storage device. Looking at how that might work and how that might be optimized. We're also piloting our Distribution Management System. We're in the midst of going through requirements set in a distribution management system and we really do feel that there is some infrastructure that's absolutely required for being able to have a robust distribution system with different distributed generation, being able to plug into the distributed generation system, and being able to manage that so you can control it and monitor it down to our distribution management system.

We've got another project looking at demand response and how we might be able to measure that in an instantaneous basis and confirm demand response to that they know we’re sending out or actually producing the demand response that we expect.

And then the Advanced Grid Demonstration Program is looking at private security from an end-to-end perspective. We also have a very large (inaudible) storage program and an eight megawatt battery, a 32 megawatt hour battery, that is being installed up in the Capuche area where we’ve got a lot of wind generation and there’s about 13 different components of that project that we’re looking to demonstrate and evaluate.

And then finally, we’ve got a super conducting transformer that we’re installing as part of the Irvine Smart Grid Demonstration Program. We’re not the lead; we’re, essentially, the site host on that one.

So briefly this is the overview of the Smart Grid Demonstration Program and a couple of things we’re doing here besides looking at distributed generation, we’re also taking a look at doing our protection and how the distribution circuit works. Right now we’ve got a radial system and we’re looking to combine two theater circuits into a looped circuit so that we can feed back into both circuits from the other. That requires a couple of different technologies that we’re using such as some interrupters and be able to isolate the outages that might occur on the system in a much more efficient way than what we are currently doing. So this is an overview of the super conducting transformer, the distributed storage, the individual homes and the different case studies we're doing on those individual homes and the protection that we're looking to redesign in this particular demonstration program.

This is about an $80 million program, again, using ARRA funds in association with the Department of Energy.

There was a series of questions concerning what are you doing on the distribution system in the near term, the medium term and the long term. So let me address those briefly. Obviously, for the details the general rate case will give you a good sense of what we're doing in the next three years from 2012 – 2014.

The near term. We are going to be completing our smart grid deployment. That will be done toward the end of 2012. Continuing ongoing infrastructure replacement. This is work that we have been doing and continue to do, would like to get authorized to do more of this in working with the Public Utility Commission on that issue. We're continuing our circuit and capacitor automation. These are programs that we've put in place probably the last 10-15 years. We do our voltage control on the distribution system using capacitors in the field as opposed to in the substation so it's closer to load to the advantage of that, a little bit of complexity on the automation side but it's worked fairly well for us in the last 15 years. Also, as I mentioned, piloting our distribution management program as part of the Irvine project. We're piloting, hoping to pilot, a self-healing circuit automation and this is really taking a look at the Irvine relay protection scheme into a variety of different locations in the California area to make sure that that not only works in Irvine but works in different types of environments throughout our distribution system.

We are also working on updating our wireless communication system. This is in anticipation of more and more need for information to be passed on that wireless communication system. We passed that system 15 years ago associated with the capacitor automation, circuit automation.

And then I skipped the one, the smart distribution plans. We're really taking a look at doing some more predictive analysis of our distribution transformers to try to reduce those failures that may happen on those transformers and get those transformers connected ahead of time.

On the medium term we're looking to implement the distribution management system. We are looking very much to leverage the ARRA program, particularly the things that we're showing in the Irvine Smart Grid Demonstration Program. We do believe that most of those concepts will be directly able to deploy so we're looking to take a look at those components of the Irvine project and implement them in our system after the evaluation process.

And then also there's about $4 billion invested through the ARRA program. We expect to get a lot of learning from other utilities on what they've done and the Department of Energy is very sincere about making sure that information gets communicated throughout the country and make sure that we take advantage of that effort on their side. Evaluate the pilot programs that we discussed above for possible deployment.

And then on the long term our perspective is there is so much going on in the sort of one to five year timeframe. There's not too much reason to get too ahead of ourselves, we think that there's a lot of learning to be done. We think we've made a tremendous investment nationwide through the ARRA program and want to make sure that we get our full learnings from that before we start planning out some things. Now we do have quite a few ideas on what might be in the five plus year timeframe but, quite frankly, there’s really no reason to do really a detailed analysis of it. We do have 10 year forecasts. We do have that information in our deployment plan but, to Jon’s point, it is subject to change and I think that’s the key takeaway.

On the deployment plan itself, we will be filing that by the end of this month. We just want to briefly give a view of how we’re looking at this. And this is a draft of the functions and the way we looked at it. It’s pretty close to what we’ll be filing next week.

What we did was we took a look at what is a smart grid, what is the definition of it, what are the different functions and of those functions what types of infrastructure is being driven by those functions. So we’ve listed over here on the left hand side the different smart grid functions – distributed energy resource integration, customer information, and plug in electric vehicle readiness and then we mapped those functions to infrastructure requirements.

The infrastructure that we defined is going to broadly be grouped into three phases. One is sort of managing control systems so these are the centralized applications and hardware associated with doing something like a distribution management system or an energy management system on the transmission side. So these are computer systems that we believe we're going to need to support these functions.

Then there's this middle layer of communication networks. We know that there's going to be a tremendous amount of information flowing over our communication networks and these are all the different types of communications systems that we're taking a look to either build or upgrade.

And then, finally, the field devices. These are essentially the devices that are being plugged in to our management control systems through our communication networks.

And we've kind of gone through the deployment plan for each of these functions to identify each of the individual systems that need to get built or upgraded and that are essentially how we've looked at the smart grid. It's a highly integrated system so it's very difficult to talk about a single component without talking about the be it all plan; that's why we're very happy to have the opportunity to get that overall plan defined on a piece of paper and get it submitted and get an opportunity to have those discussions with the Public Utility Commission and other stakeholders.

One of the sort of key drivers to the smart grid, and what we've looked it, is it really is a very complex system. A system that we've done a lot of work on how do you manage very complex in-depth system that have tremendous interdependencies at the same time not trying to get a complete command and control system that manages everything. We just simply don't believe that's going to happen. We think that there's some discrete processing that's going to happen on a distribute level that's going to tie in to some type of centralized system and really kind of go through the analysis of how that's going to work. We really are taking our first steps at that and know that we have a long way to go on that.

So that's the comments that I had on those first two sections. I don't know if you want to hold the questions and let Gary talk about interconnections or if you want to address questions right now.

CHAIRMAN WEISENMILLER: Why don't we let Gary talk—one question, go ahead.

COMMISSIONER PETERMAN: I have one question that's more appropriate for you, and maybe for other panelists going forward. When thinking about safety, what role is there for the DG customer in helping to ensure safety? And what opportunities for behavioral changes, etc.?

MR. SHERICK: Well, I think that it’s islanding effect. I mean there’s certainly intentional islanding that makes a lot of sense under a certain scenario and it’s assurance that the anti-islanding when you don’t want to be islanded gets shut off. I think that’s the major issue. And I really think that it’s going to be a process where both the utilities and the distributed generators are going to have to work together to kind of figure out what’s best. It’s going to take some time.

COMMISSIONER PETERMAN: Thank you.

MR. HOLDSWORTH: My name is Gary Holdsworth and I’m a Manager in our Grid Interconnections Group at SDE and I’m very glad to have this opportunity to address everyone. I hope ya’ll don’t mind, I don’t have any slides. So I’m going to talk about interconnection in about five minutes so I’ll then take questions.

The key thing—you know, this is mostly a smart grid workshop today. There were some specific questions addressed in the paper about interconnection and integration of interconnection. So that’s why I’m here addressing them.

The primary thing I want to talk about is that it's an education process because it's not every day that someone wakes up and says, "Oh. I wonder how generators are interconnected to the system." Right? That's just not what a lot of us are doing on an everyday basis. So some of the questions, I think, reflect a lack of understanding on the need for continued dialogue on integration of these systems.

Three primary tariffs control the interconnection process in our service territory. The first is the ISO tariff and that's for transmission level interconnections. The distribution level interconnections are broken into two different tariffs. One of which is our tariff which is called the Wholesale Distribution Access Tariffs, the WDAT. PG&E calls it the Wee-DAT. Other companies call it other things. We call it WDAT. The other is Rule 21 which is also for distribution level interconnections but has some different flavors. It has a flavor for behind the meter or net energy metering and doesn't use a lot for wholesale transactions but the line between WDAT and Rule 21 is somewhat flexible or nebulous from time to time and that is one reason why the Rule 21 Working Group was recently re-established. We're trying to work out some of those lines of demarcation a little bit better. It's confusing for everyone, including the developers, and we're trying to grow that.

The key point on the integration of the interconnection process. I want to make certain that everyone understands. In recent years, I've been working on interconnection reform efforts with the ISO for about four years now. We have gone from a very one at a time serial type process to looking at the interconnection on a collective basis in what is called Clusters. And that is done, not only for interconnections at the transmission levels but the same procedures with the same timelines occur for those WDAT distribution level interconnection requests. The studies are actually performed by us and the ISO in total. So they're looked at aggregate or collective impacts. That is appropriate, as I think was previously mentioned today, the level of demand or interest for interconnection is such that, for example, at SEU's queue we have over 3,000 megawatts of collected WDAT requests. Three thousand megawatts is a lot of power on an aggregate basis and it sure pales versus the ISO transition level where we have well over 30,000 megawatts. And that's an astronomical number but it's still a very large number so distribution level interconnection requests can't have impacts to the transmission side and they need to be addressed. They're addressed in these studies. So they are highly integrated today and the recent reforms we just passed, ISO and we passed, last year they're even more integrated. So that regardless of size of interconnection requests, if it's a wholesale transaction, it's going to be looked at at an aggregate basis. That, we believe, is the best way to plan the transmission as well as the distribution upgrades required to integrated that new generation. We will echo something that PG&E said this morning, we feel that it is very appropriate for the ISO to continue with its transmission statewide plan and even its interregional planning but we do not see any value in a statewide distribution plan. The distribution system is the last mile, so to speak. The last mile is much more responsive to things such as load growth or new meter sets and things like that. This is a necessity of very reactive construct whereas the transmission system is the backbone, to use the telecom term, and that's very much useful to have a proactive planning approach for the backbone. It is somewhat reactive but it is—it really has a proactive need to it. So the distribution system by its nature, and was mentioned, things that happen in Fresno don't really impact things in Stockton or downtown LA doesn't impact what's going on in Colorado River. That's true. So we see very little need for a distribution level plan. So those are my kind of introductory comments and I'd be willing to take questions down the panel or here, either way.

CHAIRMAN WEISENMILLER: Yeah. Let me start with a couple of questions for you and then go back to the other gentleman. First one is, of the 3,000 megawatts how many projects did that represent?

MR. HOLDSWORTH: That's around 300 on the WDAT and yeah—so the 3,000, 3,500 actually, let's round it up to 3,500. That's roughly around 300 projects.

CHAIRMAN WEISENMILLER: The next question is in terms of—do you have a sense of what the best practices are in terms of DG interconnection studies at this stage?

MR. HOLDSWORTH: My opinion is that the best practices are now implemented throughout California in that we're using the clustering approach to divide away the collective impacts on both the distribution system and on the transmission system. FERC has said that that is their preferred method of interconnection studies is the clustering approach. It's really where we get the most efficiency. If we had not gone to a clustering approach back in 2008-2009 for larges and we added the small generators eventually in there, we couldn’t even conceive of handling 800 type requests that we see today. Being able to study 800 active requests which are what’s in our system today. It’s not perfect but it’s very much the state of best practices in the industry, this clustered approach.

CHAIRMAN WEISENMILLER: It’s certainly one of the things that the ISO has been struggling with. The level of, I’ll say, the financial commitments from the developers in terms of weeding out the queue some. So the question is is that at the appropriate level at this stage?

MR. HOLDSWORTH: Yeah. That is a key question that the ISO is addressing right now in its interconnection reform efforts. And maybe I’ll defer to Neil Millar later who will be talking about that. The question inevitably comes when you talk about a very healthy, very – I hate to use the word – but robust queuing process that we have. A lot of demand for interconnection. That’s a very good thing but that also means that we need to be very efficient with what we’re doing. There’s going to be some generation that’s just not built. And determining what is and what isn’t is challenging in a market based environment. So the challenge is to take, to see, how the market can be helped to develop or to make the right decisions and to— I'm also talking about maintain protections for the ratepayer who's eventually paying for the transmission infrastructure. We need to, and I'm going to defer to the ISO on a lot of this and their plans for this, there is a need to rationalize or right size our new infrastructure that's going to be needed to meet the Governor's and other's goals. So how we get there is very complicated but very thorough. We're going through a very thorough process to get there.

CHAIRMAN WEISENMILLER: One question is, I guess, one of the more poignant moments when you read the expert panel report on San Bruno was that PG&E on the permitting side for the gas side has 22 people. Perhaps if they had had 30 that might have been dealt with. So again, how do you select the right number of people for your group?

MR. HOLDSWORTH: We are adding resources as best we can to deal with the current environment that we have and we do expect this environment to be very healthy. Particularly if we're talking about an additional 12,000 megawatts of distributed resources. So to the extent that we can find adequately trained and capable people we're hiring them and we're going to continue to do so. It's a very complex process. It's something where our—my management team and, I think, PG&E as well, we're trying to use contingency workers if we can. But we're all trying to hire the same people. So it comes down to the folks with experience and the knowledge of these procedures are somewhat of a small group. We get to the point of we need to train them and we're definitely training on a daily basis to get the skill sets we need to be able to address these. It's a somewhat of a bootstrap approach but it's how we're addressing the issues.

CHAIRMAN WEISENMILLER: I guess in terms of, the last two questions—actually one of you may want to chime in. The first is that obviously we have a lot of constituents talking about, for the 12,000 megawatts, where it should be. Should it be in environmental justice areas? I guess, putting on your system distribution planning hat, where would be the best spots in the Edison system in terms of reliability, resource adequacy or – just from your perspective where would be the best spots to put DG in your system that would have the most benefits from the system operation perspective? Either one of you can try that, obviously.

MR. SHERICK: I think at this point we have an interconnection queue and a process and we address that in a much more reactive basis. On a proactive basis, I think, you would have to see what the market is incentivized to do, to some extent. From our perspective we need to look at all areas as possible places for interconnection so we're not trying to tell someone that they can't interconnect here but can interconnect here. There are certainly a lot of areas where we have a lot of growth and those would be areas where we'll do a lot of our planning process to manage that growth. With the economic downturn that's been a little less of an issue for us but it certainly was an issue three or four years ago and could very well be an issue going forward. So those places where there's a lot of growth would probably be the best areas for, if we could, ideally choice the location for where distributed generation is being placed.

MR. HOLDSWORTH: And to add to what Robert is saying, I think he's primarily talking about load growth or where the load is and unfortunately in our territory our best resources is where there is no load. It's out in our deserts and in our mountains. And therein lies the transmissions needs, the immediate, transmission needs. We have said in many different venues that distributed resources have a real role with where there's lots of load in our metro area. Unfortunately, the land isn't there that a lot of these resources require. So that’s one of the reasons that we went into our commercial rooftop program is we have a lot of flat roofs in our area that we can use. But those are small. Again, it’s trying to find a balance from a number of stakeholders, not just—we’re going to—the market is going to do what the market’s going to do but at the same time we have put out maps, PG&E has maps as well, of locations in some of our areas where a circuit may be able to handle some additional generation. We have maps like that for our rooftop program as well as for our RAM program and I believe PG&E has similar things. We’re trying to give a lay of the land. We’re not telling people where to go but we’re giving them a lay of the land.

CHAIRMAN WEISENMILLER: Now, do you have a sense for your smart grid program the delta between replacements versus modernization? And the cost?

MR. SHERICK: I do not have those numbers off the top of my head but we can certainly get those in a written response.

CHAIRMAN WEISENMILLER: Okay. That’d be great. Thank you, thank you both.

MS. KELLY: Our next panel member is Tom Bialek from San Diego Gas and Electric. Tom has a Bachelors and Masters of Science Degree in Electrical

Engineering from the University of Manitoba. He has a PhD in electrical engineering from Mississippi State and he's currently employed at San Diego as the Chief Engineer on the Smart Grid Team. His current responsibilities involve smart grid strategy and policy for transmission distribution issues including equipment, operations, planning, distributed generation and development of new technology. He is also the principle investigator on DOE and the CEC's funded microgrid project. Tom?

MR. BIALEK: Well, thank you. It's a pleasure to be here Commissioners. We appreciate the opportunity to talk to you about this issue. I actually tried to take a stab at answering the questions on planning for the future as well as interconnecting DG, maybe not quite the format in which you laid out but hopefully you'll be able to get there.

So, I think one of the things that was asked is what is the vision of the future. So for SDG&E, as part of our smart grid deployment pilot, we looked at what is the smart grid utility vision. And what you see here is really the definition from a transmission perspective, from a distribution perspective and there's also a customer perspective. Now when it comes to customers, because I know later on there's a question about the role of customers, as we think about the future, looking at the distribution system, being able to look at the burden of balancing storage, reliability and integration services to customers and giving the customers options to participate. We believe these are ultimately the longer term version of where this smart grid will take us. Clearly, from a transmission system is improving the speed of response.

So why did I bring up transmission? I think one of the things to think about when you talk about 12,000 megawatts; you're really looking at 12 1,000 megawatt plants. Those are large plants. They have large impacts on the grid and I think our Senior VP, Jim Avery who came to the last workshop talked about when they looked at it from a transmission planning perspective they say overvoltages, they saw high flows, they also saw transducer stability problems. The solutions for those types of problems were anywhere between $350-550 million and that's a transmission issue. So the point here being that while this is all about distribution, given that these large numbers are being proposed, it will also impact the transmission grid.

One of the things that you asked a little bit about is the vision of how this moves forward. I'll take a little bit of time, very briefly, to talk about our deployment and how that figures into planning. So we've got nine different program goals. Ultimately projects by year, value pilot and then the total number, ultimately, in our deployment plan is 64 projects, each of them with their ARRA price projects but they are not included in the costs and benefits so for a grand total of 82 projects. And within the context of that, we're able to—given those different nine program areas, and integrated renewables being one of them, we do have vision statements for both 2015 and 2020.

So here are these nine different program areas. Certainly for this particular discussion here, the area of renewable growth and customer empowerment as well as reliability and safety are issues, and operational efficiencies, are issues that come to mind when we think about how we're going to integrate this large amount of renewables.

There's also a question with regard to what ARRA funding can SDG&E get. SDG&E has applied for two and got one. Ours is really a, what we call at SDG&E, a communications systems. And really, you heard Edison talk about their effort to upgrade their RF—their wireless RF network. This is actually a project that we'll do too. A multilevel RF, controlled by a single service, and what you see here, realistically, are some that now are integrated, that security has integrated management control, but looks to top the various assets on the grid. Looks to control various assets on the grid. And looks to empower our workforce by providing data and information. This was a roughly $56-58 million project, $26 of which came from DOE and $26 from SDG&E and some money from the CEC.

Here specifically is when you start talking about the types of projects that we are actually going to implement as far as integrating renewables or distributed generation and integrating these into our grid. So you see here in our grid, basically, in the 2012-2016 timeframe, Distributed Energy Resource Management System. What you see with that system is that that is a system that will actually look at providing information that allows consumers to actively participate in management of the grid.

You can see in our grid vision by 2020 that this Distributed Energy Resource Management System is fully functional and interfacing with customer loads and resources supporting efficient utilization of distributed energy resources. We believe from an operational efficiency perspective that is certainly one of the areas that we are putting in place.

And the idea of dynamic line ratings, other, I always imagine, detection systems or elements of these overall strategy for integrating high penetrations of distributed energy resources. Specifically around renewable energy growth, we do have a number of projects. And these projects were also included in our general rate case application. We look at mass energy storage from a distribution perspective to integrate that with the renewables that are increasing on our system, circuits that have high levels of renewable penetration, putting our capacitors on SCADA, allowing us to better do volt VAR optimization on the grid in response to what's going on with the PV or other renewables or DG, expanding our SCADA. We are approximately 70 percent of our load is behind a SCADA switch today. Roughly 80 percent of our circuits have SCADA. We see that SCADA is a necessary need to be able to control and move loads around and balance the voltage and power flows on the circuits. We also talk about dynamic lines rates. So if we think about actual circuits, but I think this gets to one of your points, why would we—the question of replace, refresh versus a new smart grid technology. To the extent that we can leverage dynamic line ratings on a distribution systems and transmission system potentially allows us to the defer capital expansion, and hopefully from an integration and renewables perspective actually makes that easier as well. And then lastly, phasing out measurement units on the distribution system; really looking at that more to provide time stamp data and coupling that with the other elements here. You can now look at the potential for closed loop command and control of storage and other systems to actually mitigate the impact of PV. And you can see the vision statements are over here on the right. We'll also talk about the whole idea of advanced control as well.

One of the things that we talk about integrating the renewables; we'll talk about it a little bit later. Low power watt area indication network, a good comms system, these are all sort of systems that go across boundaries that will us to utilize and allow us to make data available. I think one of the keys, as we think about the higher penetrations of renewables and PV, is the fact that we need more data to be able to manage this system. The system is going to become increasingly complex. We're going to need that data and information to be able to manage the grid. And we see some elements around data management and analytics.

So this is just sort of a summary, it gives you a little bit more detail around, what I think Chris pointed out, I think one of the questions was societal and environmental benefits with regards to our smart grid deployment plan. We didn’t do that estimate. We did work with the Environmental Defense Plan. And we can, ultimately, you can see the numbers represented here.

I think one of the things you should take away from this particular slide with the cost of benefits is that you see on the top categories previously authorized investments. So these are the costs that are built in from 2006-2020 timeframe of existing projects that were already authorized. And you see also our 2012 test years and rate case process going up to 2020 or 2010. And you also see other programs that are in existence and then you also see incremental projects. These are projects that are incremental to what we are asking for in our GRC and that have been approved by the Commission officially.

So here’s sort of a breakout of how we looked at the societal benefits. And we looked at it for really both large-scale 32 percent RPS as well as centralized renewable energy as well as reduction by integrating distributed energy as well. And then we also did some work around electric vehicles.

So at SDG&E there really are a couple of ways to look at what are our concerns. We have operational concerns, engineering and planning concerns, we have regulatory concerns. The operational concerns are really driven by the invariability of the PV power output and other various points here. To the point of interconnecting generation, the whole idea of the impact on capacity planning, the impact on volt VAR management, the impact on conservation of voltage reduction regulations within the state. An additional key element is electrical models. When you think about trying to integrate these types of systems, how do you actually model these? We've got today an existing local program but it's good for static types of calculations. We're seeing increasingly a need for transient announcement tools and associated transient announcement capabilities. And on the regulatory front, something that's been addressed already, are things around Rule 21. Changes to Rule 21 to allow us to better integrate renewables. Rule 2 around service power quality and then ultimately cost causation principles.

To the extent that you can see here our generate rate case specifically around renewables for our test year 2012 we have for these different projects, $54 million in the rate case. And, as you can see, the allocation of cost across the projects. And there's also some future smart grid deployment projects.

So one of the things that we think is important is that you're able to map where these installations occur. So this is the mapping of all these PV systems on SDG&E service territory. We map them into our GIS and we're also comparing electric vehicles as well.

And I think to the point that—SDE's point is that where do you want to site the 3 ½ megawatt type PV systems. It's really in SDG&E's backcountry where very small wires, very small transformers. Where people talk about distances between substations in the magnitude of four or five miles and we have some small Level 4 conductor for example and if you look at what that means, the fluctuations would be unacceptable on those particular circuits and therefore requires a significant capacity upgrade by reconductering at a significant cost.

Here's why we believe that we need smart grid to address some of these issues. I think some of you have probably seen this type of graph before. PV output of a particularly favorable day of one particular circuit. The bottom is one second data. The bottom actually is the expanded version of that above version and it shows ten minutes. I think one of the challenges here when we think about integrating renewables is when we see these dips here, we’re seeing basically a couple of things. We’re exceeding our constant voltage limits. So when we talk about integrating distributed generation we’re nominally trying to keep between 126 – 114 volts to meter, for CVR program it would be 120 – 114 volts per meter. So just multiply by a thousand in this particular case. And you can see that we are well above our normal operating limits however what you’ll also see is that this is actually within the allowable operation range under Rule 21. The other challenge with this of course is that this will now cause our regulation equipment which we have installed; it will actually operate the time zones that are shown here.

And you can see why we believe that we need to take—why we need to be proactive as far as modification to the system to allow PV to actually be incorporated and you can see here circuits here with 30 percent PV and those with greater than 30 percent of PV. These are sort of the worst conditions with light load on the circuit and high PV output so that’s sort of the worst case. And this is actually a worst case that today under Rule 21 that is not looked at, they’re actually looking at 15 percent of the people behind line load section rating so it’ll probably change when it does happen and get into Rule 21.

So we believe ultimately that there are never changes that are needed. From a regulatory perspective, the question with regards to Rule 21, you heard about Rule 21 WDAT modifications to allow the appropriate ability to model the system as well as the ability to actually change the requirements for performance. Also looking at periods of low load, high PV output, things around low voltage ride through and frequency droop to make these converter actually perform in a more grid friendly fashion as opposed to what they do today which is operated unity power factor, operated predefined limits and drop-offs when those limits are exceeded, rule through modifications around harmonics and voltage, things around cost causation with a real regard to costs and incentives so that particular system that you saw here actually relies upon the grid to take care of its smoothing. That’s a function that today is born by the utilities and the ratepayers. So we that actually gets into the next session.

I think we expect that there’s going to be some significant impact on not just the distribution system but the transmission system. There needs to be technical studies and we are doing some of those studies today to look at what we can do whether it be from a policy perspective to add additional functionality into the converters or actually what can the utility do to put systems in place similar to alert to what we do today with the capacitor banks on the grid. One of the things, that I think, is really lacking in general is actual field measurements. That data that I showed you is one of the few actual sets of data I've actually seen. There's a few others, there's not a lot. But that data is necessary ultimately to be able to model the system. And I think when we talk about adding additional amounts of distributed generation of PV we do need to understand what's actually going on and be able to model the grid. And we do need data to allow us to look at before and after. Changes in regulatory technical status, we talked a little bit about those. And lastly, adopt lessons learned from European countries. Germany has, for example, 18 gigawatts of PV installed. And they've added new grid codes. SDG&E believes that those types of requirements for moving forward in the future are necessary. We believe that the time to start is now opposed to waiting.

CHAIRMAN WEISENMILLER: Thank you. A couple of questions. First one was when we did talk about the European experience, one of the messages seemed to be the visibility for the Cal ISO on the production, at least that wasn't one of your Rule 21 items.

MR. BIALEK: We've had this discussion before with the California ISO and we have gone up and met with them to discuss what level of visibility do they need. How granular should they be presented for them. Clearly, if you look at telemetering data and information to the ISO at a very granular level it would probably be very cost prohibitive. So the question becomes at what level do you aggregate that information and up and present it to them? And what sort of forecast do you provide to them? Forecasting is a significant issue as well. So based upon the conversations I've had with the ISO, I think that's a going forward discussion as to what level of visibility do they really need to actually operate.

CHAIRMAN WEISENMILLER: And in terms of best practices. It sounds like what you're pointing us toward is Germany on this set of issues. Again, I've been pushing people trying to understand a consensus on best practices in this area.

MR. BIALEK: Well, I think certainly given the amount of penetration that they have in their particular grid, I think, that we should take advantage of the lessons that they have learned and the realizations that they have come to. And one of the realizations that they have come to, and this is based upon conversations that I've had with some of my German colleagues, is that with these units today operating basically a unity power factor with limited control, although they do have control at 100 kilowatts and above, if there's a major transmission event it will cause all of the systems to drop offline typically. And so you'd lose 18,000 megawatts of generation and they do not have adequate reserves to recover from that. And they are worried. So part of the challenge, and that's why they've added these additional grid codes, is to allow some flexibility so that the system going forward is more flexible and can recover more from those type of events.

CHAIRMAN WEISENMILLER: Okay. The last question is if you have a sense of the delta in cost between the replacement of stuff and / or the modernization on the smart grid package.

MR. BIALEK: So, I would say that the—we saw the smart grid evolution, not necessarily revolution, we had a lot of internal discussions on what is smart grid. What projects are smart grids or not. If you add some additional functionality to the distribution circuit upgrades would that make it smart grid? Would that make the whole project smart grid? And the answer is, we debated that back and forth, and there was no real clear consensus. Although we did try to err on the conservative side and not call everything smart grid because we believe if we did that that would be problematic in and of itself. So we have—our capacity plan—our ongoing capital expenditure budget at a distribution level is on the magnitude of $10 million a year. You see projects here on the magnitude of $50 million a year. So roughly, you know,---but what we do see is that, and what we have said, is that as we move forward in time and as we rollout future distribution system and capacity system upgrades we are going to leverage the advances that smart grid brings to us. What you will see is a further blurring of what is really smart grid because what you're going to see is new products and new standards which will incorporate what today we're calling smart grid technologies but what will become standard designs.

CHAIRMAN WEISENMILLER: Okay. Thank you.

MS. KELLY: One last speaker. Not last but Neil Millar who's the Executive Director of Infrastructure Development at the ISO. And he's just going to provide comments on mainly integration of 12,000 megawatts at the transmission level.

MR. MILLAR: Thank you and thank you for the opportunity to present today. I also didn't bring slides. But I'll also keep my comments relatively brief. As many of you are aware, the Cal ISO does have essentially a companywide initiative this year looking at taking the necessary steps to be proactive and to be ready for the integration of large amounts of distributed generation. Those areas of interest really factor into the nearer term the operational side.

Do we have short term forecasting and adequate visibility of the amount of distributed generation so that we can take that into account in managing variability of the system?

In the midterm, do we have the right market products available to provide the kind of reserve requirements, ramping and load following capabilities that we need to handle intermittences or variable generation; whether it's on the distribution or on the transmission side?

And then on the longer term, on the transmission planning side, there we're looking at what fleet replacement do we need. How do additional systems need to be put in place? What additional operating systems do we need to take into account so that the system itself is properly positioned?

When we look at the transmission planning aspect in particular and we look at coordinating distribution planning, the technical issues I think are generally well coordinated. There are relatively distinct lines between where the transmission system ends and where the distribution systems begin and how to manage the technical issues crossing those barriers. The bigger challenge in coordinating the planning aspect right now, I would be encouraging more focus on what is driving particular types of distributed generation and what is driving the location because as the quantities and the locations are, and the type of generation, are pretty fundamental to both of the systems and the issues that we have to take into account. Unlike the distribution system, we heard this morning that some of the tools on transient and dynamic stability analysis and so on are likely need to be applied to parts of the distribution system that they weren't previously. On the transmission system those tools have been required for many years but we will need different models and different modeling capabilities and to be able to take into account the uncertainty around the location of the resource as well. So those are the major issues that we see. These again are the how much, where and the type so that we can proactively take those into account in our annual transmission planning processes and have the system properly prepared for that new generation coming online. The only other factor that I should mention, and again it relates to the location, is that distributed generation does have the capability of shifting load patterns on the transmission system in a number of areas and that could also drive new requirements that we need to take into account moving forward. So again, I just want to stress that we do see the need to coordinate with the distribution planning function and it’s primarily in the case of looking at these kinds of resources, the location, the models that we need to take those into account. Not so much the technical issues that cross back and forth. Those are better understood, I believe, and aren’t the unexpected issue that we see coming. It’s more of the quantity that we need to address. I’ll leave that for the comments and am now open to take questions.

CHAIRMAN WEISENMILLER: Yeah. That would be good. I have a couple of questions. So the first is how do we get resource adequacy values for DG, how do we get DG value and resource adequacy in context?

MR. MILLAR: We have a few different ways of looking of trying to expedite interconnections right now for distributed generation that would be of a magnitude that would be studied for these purposes. And those methods generally leave the resource adequacy deliverability issue until the next cycle and we can study, in aggregate, the resources that want deliverability. So we don’t have a clean way, right now, to integrate deliverability requirements into a fast track process for a smaller distributed generation aspect. The main reason is because the location does matter. In areas that are clearly low pockets were generation is coming in strictly from outside, the answer should be more obvious. Many load pockets are however along the way between generation resources and other load pockets. Even though a distributed resource may be netting a load at that point, it still should see a load pattern that may cause patterns for some other resource for what was previously conceived to be deliverable. Right now we have a bit of an awkward fit that we’re looking at. We are taking steps to further integrate the transmission planning process in aggregate with a generating interconnection process to try to find a solution. We think that there are some possibilities there to try to find pockets where we can give the green light to but that’s still speculative at this stage.

CHAIRMAN WEISENMILLER: I guess the last question is, again, circumventing things but where are the general locations that would be the best and where are the worst locations?

MR. MILLAR: The best locations would always be near the load centers from a transmission perspective. The worst locations would be back where we already have generation. The comments that we heard today though are that a number of the resources in the two, three, five megawatt range looked more attractive from a resource perspective but were where we already have large blocks of generation.

CHAIRMAN WEISENMILLER: Thank you.

MR. MILLAR: Thanks.

MS. KELLY: Chairman, what I'd like to do is wrap up this panel. We're getting late. I'd like to open it up for questions here from the audience and then attendees of the WebEx. Is that all right with you?

CHAIRMAN WEISENMILLER: Yeah. That'd be good.

MS. KELLY: Does anyone in the audience have any questions? Dave, come on up to the podium.

DAVE BROWN: Actually, just a question for PG&E. The volt VAR optimizer or the volt VAR technology that they were talking about demonstrating, could you describe that a little more about what the technology is?

MR. THALMAN: The volt VAR compensator is basically a powered electronics device out on the feeder with the reactors and the passers behind it and you can adjust voltage. It allows you to do it dynamically instead of with discrete switching. The pilot that we're looking at is testing how effective that would be and its effective compared to other options.

MS. KELLY: Any other questions in the audience? Yeah? And please give your name and who you represent or where you're from?

MR. BATESON: Gerald Bateson and I'm just representing myself today but from a standpoint of tradeoffs and modeling, San Diego Gas & Electric has microgrids and part of the project is coupling those. And I was kind of curious of if in your modeling if you're doing some trades to some of the more expensive microgrid integration versus some distribution generation being further out and how that is being considered.

MR. BIALEK: Well, if I understand the question correctly. When we look at modeling typically around the normal, steady state of analysis—of Level 1 analysis, we do have conventional program. When we look at the impact in renewables, usually PV in this case, we're looking at transient models to try to better understand what's going on. When we think about microgrids now and incorporating microgrids because we have pilots going forward in Loreto. Our ODMTS system which is actually going to be functional at the end of this year has an unbalanced three-face multiple part program and will have some additional analysis. The challenge will be to look at when you decide to disconnect how often and how frequently you would end up having to run that unbalanced program because looking at that really that particular instance to manage the voltage, the frequency and the power factor within the appropriate ranges. So hopefully that answers your question.

MS. KELLY: Any other questions? All right. We have one question from the web. It’s for PG&E I’m told. And it’s going to appear up on the screen. It’s from Barbara George.

MS. KOROSEC: I’ll go ahead and read the question. It says, “PG&E’s testimony in the 2011 GRC revealed that it ignored solar PV and energy efficiency in its load forecast because it doesn’t know where it is. PG&E load forecasting methodology does not particularly adjust for changes in peak loads because of increase customer photovoltaic installation, customer energy efficiency programs or increased load due to PV increased penetration. The effect system wide programs have on peak loads are not easily quantifiable on a DG level, division or geographic area. Therefore PG&E

cannot know exactly where reductions or increases will occur. This is from PG&E testimony, Volume 3, page 9-12. Is this still true? PG&E knows exactly where every good connected PV system is installed because PG&E hooks them up. PG&E also knows where energy efficiency measures are installed however PG&E has not tracked this important data. When will PG&E and other utilities begin to report this data?"

MR. THALMAN: Okay. I will play out what seems to be that the person asking the question already knows their answer. PG&E is endeavoring, obviously, with our, what I mentioned earlier, with our ability to record more data and to track these items. There's a lot of historical data, rather, history behind PV installations to know where they all are. I do like SDG&E's map that showed that they know where all the PV resources are. I think that's our target. So I guess my answer is that we're working better to record and know all of the data that the question is asking so that we can know how it influences our load forecasting. I will add that the load forecast, that there are two levels here. There's knowing the data and there's also knowing which point it's going to significantly impact your load forecast. If we rely on historical data, the impact and penetrations of electric vehicles and PV have not been significant enough to—you can look at your error bands on your load forecast and your forecast for those items are still within your error bands, and so if I remember correctly the point in the testimony is not so much that we don't know those, it's that it's the current levels are near error bands and so it's not a significant impact. Now, certainly, that's not going to be the case going forward and that's why we're tracking the data.

CHAIRMAN WEISENMILLER: Certainly if any of the panelists want to comment further in respond to the question, you can certainly do that in writing.

MS. KELLY: Right now, I'd like to make a small adjustment to the schedule. Kurt Yeager is here to speak from the Galvin Institute and has a commitment that he has to be in San Francisco in a very short period of time. So we're going to move him to come up and speak now before the second panel and that way he can make his appointment in San Francisco. And I have to dismiss the first panel, thank you very much.

Mr. Yeager has joined the Galvin Electricity Institute in an effort to perfect the electric power system shortly after it was launched by former Motorola Chief Bob Galvin in 2005. Yeager worked with electricity experts, innovators and entrepreneurs to design and build perfect power system models of a smart, efficient electric power system that cannot fail the consumer. He also leads the initiative in driving the electricity power changes necessary for system transformation at the state and federal level. Mr. Yeager?

MR. YEAGER: Well, thank you very much. Indeed it’s a delight and an honor to be with you this morning and thank you for adjusting the schedule to permit me to participate. Unfortunately, I had a previous commitment that I have to meet today with a Board.

I, of course, have been a longtime resident and ratepayer in California. I spent 30 years with the Electric Power and Research Institute and spent the last eight years as the President and CEO working closely with the utilities here in California. Since then, our work with the Galvin Electricity Initiative has been more in other states; it’s only been recently that we’ve only started working with it in California. I’m delighted that we have that opportunity now because California should be the leader in this transformation.

When Bob Galvin invited me, when I retired from the EPRI, as I had the privilege of knowing Bob for some years and he’d been on our advisory council, he said, “Kurt, I know your frustration with the lack of innovation in electricity as that’s where telecommunications was 30 years ago. A lot of pent up innovation and a business model that has no incentive for innovation.” So this is not fundamentally about technology, which is sitting on a shelf that’s been there for decades, it is about transforming the business model and the policies that restrict today’s utilities from really progressing.

I think it’s important to note a couple of basic principles here that I think that we’re all aware of but it’s good to be reminded because we must think outside the box. You cannot think about how we can incrementally change the status quo. No. This is a transformation. Electricity is the engine of prosperity and the quality of life. Everything we have depends on electricity. Utilities are clearly the most important industry in this nation. Our whole future depends on it.

The reason that Bob Galvin and I are doing this after we retired, we had pretty good careers – his was better than mine but I have nothing to complain about, what is the legacy that we are leaving for our grandchildren. This country is going downhill and the electricity foundation which we created in the depression in the 1930s has got to be reinvented for the 21st century. And our competitors around the world are moving much more aggressively in this matter.

Electricity, first and foremost, is a consumer service based enterprise. It is not about bulk energy, dumping it at our doorstep. It's about the quality of service that can be provided. We are still in, and in fact I would say almost before the black rotary telephone era of electricity, and we have to move to the internet equivalent era. And if we do, and I'll talk more about that in a moment, the benefits will be immense.

Technology can indeed relieve the cost pressures that we've had a taste today at every level of our economy through elevation of electricity service and value. This is not about shaving a couple of dollars off my or your electricity bill. That certainly can be done. But the real basis of this transformation is job creation. This country has become the world's greatest exporter of jobs and the electricity system is certainly a major contributor to that reality. If we are going to get back to a global leadership in innovation it's got to start with electricity. And that requires transformation of the infrastructure, the policies and the business model.

I was very pleased last week. I was invited by the White House to go to Washington for the release of their 21st century grid policy framework which I'm delighted to see at that level reflects a great deal of the recommendations that we have made. It remains to be seen whether there will be more than what I call political rhetoric however because both parties before the last election were on record at the very senior level saying that the transformation of our nation's electricity system was essential to its sustainable, economic, environmental and energy secure future. And that is the bottom line. So that is not one party. This is a bipartisan issue that has to be implemented. It can't be implemented in a month or a year but it can be implemented in a decade or two but it requires consistent leadership.

And so these are the four points: align the market and utility incentives to accelerate smart grid investments and a point here that this is a matter of state regulators who forgot to do that, unlock the utility sector innovation potential again they point to the states, empower consumers to enable informed decision-making. Only at the federal level do they focus on improving grid security. I believe, ultimately, I don't want the federal government to run my power system but I do believe that we need the federal government to establish standards and hold each state accountable to those standards. Bottom line, and to quote Bob on it, America cannot build a 21st century economy with a 20th century electricity system.

I'm pleased that I see increasing frustration at senior levels in utilities. I was at AEP a week, two weeks ago, in Ohio and I interact with a lot of utilities around the country. I was down visiting the San Diego Gas & Electric awhile ago who I view as one of the leaders in the transformation effort and a comprehension basis. "It's all about the customer today but we know very little and have no regulatory incentive." These are quotes that I'm taking from various CEOs and very senior leaders in utilities. "Customer price transparency is key with education and automation." I'll talk more about that in a moment. "And our infrastructure and policies are legacies of the 1930s indeed." That's how we were until the depths of the depression. Until we electrify this country, we'll never get out of the depression. Well, we will never get out of this so-called recession until we re-electrify this country. It may not be as deep a hole but it will be a longer, longer, longer, downhill run until we do this transformation in a comprehensive way.

And we have to get beyond the infrastructure and the policies that we established in the 1930s. We finished that job 50 years ago but we're basically still operating under the same set of realities.

A quote I like to use is from Henry Ford, "You know when I asked people what they wanted, and they said 'Faster horses.' " And that's basically where people are today and I would say unforuantely a lot of people in utilities as well. This is not about a faster horse. This is about the equivalent of opening the door for automobiles. And just as when automobiles—there was no incentive to pave roads until we had automobiles, we've got to pave the electricity roads today and, again just as with automobiles, it's primarily the communities. It's the distribution system. And I'm delighted that this conference and more and more, we're really focusing on the distribution system because that's where the action is. We can bring wind power in from the Dakotas but that's trivial relative to the whole process of transforming our distribution systems to enable all of the objectives that we are trying to achieve.

So we are working in a number of states and communities because regrettably community municipalities, where the stockholder and the ratepayer are essentially one and the same, tend to be more progressive in transforming. And we're working with a number of communities who are saying, "We're losing a number of jobs." And that people were losing jobs and companies because they're saying the electricity service reliability is too poor. So we're working building microgrids in a number of communities and the universities that bring together all of these pieces.

And the whole idea of these demonstrations is that consumers are not going to believe anything I have to say or anything else from other people. They're going to believe what they feel in their hip pocket. "Are you taking money out or are you doing something to put money in my pocket?" And these demonstrations are demonstrating that the payback is almost immediately at least three to four to five dollars for a dollar invested. So this is not about raising electricity rates or raising taxes. Done properly the system can be done by opening the door primarily to private sector investment but we've got to recognize that the key to transformation, as it was in telecommunications and every other industry, is opening the door to entrepreneurial innovators. And that's why California should really be a leader because you've got Silicon Valley here which has got the bulk of it and is where I interact with all of my colleagues in Silicon Valley.

They have immense frustration over the lack of access to the market in a way that would allow them to make money so that they could invest money is amazing. And, of course, I know and used to be good friends, and some of them still are, with utility CEOs like John Rowe of Exelon for example. He said, “Kurt, I agree with you entirely but if I did what you want me to do today, my stockholders would fire me tomorrow.” That’s what we have to recognize, that for investor owned utilities that we have to get all the key stakeholders together. Stockholders, regulators, the ratepayers, the inventors and all say, “Okay. This transformation has got to happen. We’ve got do it now. Not a decade from now but now.” And we’ve all got to recognize that we’ve got a common denominator of value among us to make that happen.

Now you’re going to hear from Craig Lewis and here in California in the last year, I’m delighted that the California Clean Coalition and the Community Choice Aggregation Group in Marin County, that we’ve engaged with them and are working with them to try to advance some of these concepts here in California and adapt them to make them effective here in California. I’m delighted that Community Choice Aggregation did not get destroyed a year ago. The Community Choice Aggregation is an important dimension of opportunities for communities, not just to aggregate load, but to ultimately to really raise the bar on the quality of service for their distribution systems.

I know PG&E does not agree with this number here. I’m really going to defer a bit to Craig Lewis who’s going to be talking a bit later on the California Clean Coalition on a couple of these numbers. Certainly from my experience, and someone whose home is in Aptos Hills and all the farmland of 15 acres, all entirely run by solar energy. And I don’t get much of a bill from PG&E anymore but I also give them as much energy as I use. If I had a feed-in tariff, I would put in a storage system and I would be quite willing to sell that power back. There is no reason why, with the dynamic pricing, you ever would need to build anymore peak generation. Consumers and buildings should be the generators.

As you know Germany and Spain, particularly Germany, are moving particularly aggressively in distributed generation with a power system that is not that advanced; although I would say that they have made some improvements. However, I would say that it is not that advanced and not that fundamentally different from ours. If we had the modernization of the grid, of the distribution grid, we will have all of these benefits as well and that's where the focus really needs to be again. On the distribution grid. But comprehensively, not say only as distributed generation. Distributed generation is one dimension of a modernization process but you have put them all in a package and go forward accordingly.

Smart grid—and I don't like to use the term smart grid because it is so abused. Intelligent grid, to me, is a much more appropriate grid. A smart grid is a transactive network, seamlessly connecting networks and consumers. Right now the grid ends at the meter. No the meter is not an Iron Curtain with utility as prisoners on one side and consumers as prisoners on the other. The end of the grid should be the end-use device in the business or home. And then as an absolutely open, free flow of information and energy at all times literally at the speed of light. Right now we have a power system, when I talk to people and they don't know it very well I say, "What would you think of a railroad that took you 10 days to open and close the switch. Would that me a smart or a dumb railroad?" And they say, "Oh, that'd be a dumb railroad. Nobody would do that. You wouldn't move the transmission anywhere else." Well, that's where we are in electricity because we’re still operating with analog electro-mechanical control and relative to the speed of light that energy is flowing, even though that might be a switch equivalent to a 10 day delay. So if the lights all went out in Palo Alto and surrounding areas last year when we had that plane crash, there’s no reason for that kind of things to happen today. That should be isolated so that it is a very, very small point.

Price response of end-use devices. This is not to send people price singles and it’s an open market. Not everyone wants it. Not everybody buys a cell phone the day it came out, I certainly didn’t. My grandchildren tell you me, “You talk a good digital line but you’re as analog as anyone we can consider.” They do things with cell phones and computers that I don’t have a clue to what they’re doing. But it is the younger generation that’s really going to make the businesses explode positively in this whole matter. But it’s going to require empowerment, the internet empowerment, by virtue of sending the signals to all the devices in the home or business and you simply say when price gets here I want this to shut down 10 percent, 20 percent, 50 percent, 100 percent. Whatever. And it can be managed entirely. And as you move forward with distributed generation, when the price gets here I want to sell my excess to the grid. And if we have a truly intelligent grid that will be very easily done. And it will save everybody a great deal of money and create business opportunities, particularly here in California that are missed.

So you have to remove barriers to retail competition and by that I don't mean how we work in Texas, I don't mean how many suppliers of bulk energy, I'm talking about the competition. Open the door so that the services that will allow me to use the information about my cost and use of power most effectively so that I can go to Google Earth or Cisco, or whoever I want to go to, and get the systems to make it all work. This will both tremendously increase consumer and producer benefits.

Engaging customer acceptance. As I say, words will not do it. You'll have to engage them through dynamic rates, technology and education, motivate through savings and automated control, prices to devices; and the light through easy, enjoyable, fulfilling experiences. I can't even imagine someone my age but as I talk to people in Silicon Valley the kinds of things they bring forward if we had the electricity equivalent to the internet would be amazing. And the amount of things people would buy would raise the value, you might sell less electricity, but I would bet you the value of a kilowatt hour would go up dramatically and no one would need a rate gun pointed at their head. They would buy it because they wanted the use of the tools.

So that to me is the really—is really the key here to customer acceptance. And that's what we're doing in a number of communities around the country now and working with people so that we can demonstrate that so people can really understand. And early adopters, so as early adopters, not everybody at once. You don't force real-time pricing at everyone, it's there if you want it. If you want real-time pricing, we'll give it to you. You can use it anyway you want; it's your information. It's not my information. It's your information. And that is the key here to work toward that.

So as I wrap up here with some intelligent policy recommendations that we put together, again, working with communities in several states. As I said, Texas, we're working very strongly in, obviously, Illinois, Pennsylvania, Massachusetts, California not yet. California is much more advanced in renewable energy and many of these other dimensions California is not. And it has to all be done in a comprehensive manner. So provide consumers with choice of access to transparent, real-time electricity pricing, recognize that all customers' specific data belongs to the customer, and establish strict district reliability and efficiency standards. The standards we have in this country aren't worth the paper they're written on. This country—the average reliability of electricity is among the lowest in the developed world. The average consumer in the United States is out of power four hours a year. It doesn't sound like very much but if you've got a digital business, when a fraction of a second will shut down your assembly line that's tremendous. And there is no country, major country, that we would use a competitor, in Europe or Asia that has that poor of reliability. And that's just one dimension but it's a very important one. Hold utilities publically accountable to specific performance standards. I'll wrap up my show with a couple of those standards. This again, the public needs to understand however their money is being spent in the distribution system. Is it just being spent to bring in more bulk power from the outside or is it really being used to upgrade the system? Link utility earnings to service quality not quantity of sales. Performance based rates. And San Diego Gas & Electric is a good example of a company that makes more money for its stockholders now even though they sell less electricity. So while there's decoupling has gotten a bad reputation, it may be used a bit, but performance based rates are essential to our future. Expand net metering to include physical and virtual aggregation. And of course this is where distributed generation comes in very importantly, enable retail energy management service competition to incent entrepreneurial and utility innovation. But it's going to be the entrepreneurial innovators that are going to bring this forward. AT&T knew all about cell phones and didn't want to touch it because they were in the black rotary dial phone business. They make a lot more money now in the cell phone business than they ever did in the black rotary dial phone business. But that was the status quo. This is not an indictment of utilities. It is the status quo and if I'm running a utility, I have to take money from my stockholders living within the rules as they exist. I can't jump outside of those rules so all of us come together and help lead this transformation. And require absolute operability as smart grid components. One of the biggest challengers that we have because missed, word quotes "missed", on this getting there has again there's a lot of pressure as we have over 250 standards that are now used across the industry which is the very opposite of interoperability. You go back a 100 years, General Electric and Westinghouse as well all designed different design plugs for the wall. We have our design plug in your house than you can only buy stuff from house. But they pretty soon found that that was not a market advantage. All that did was limit the market. So we have to recognize the absolute interoperability for security as well as operational purposes must be done. The states have got to hold the fed accountable to get that job done quickly.

Wrapping up here. We have created what we call The Perfect Power Seal of Approval modeled after the LEED Building, smart building, and model to provide specific criteria and measuring levels for consumer empowerment, efficiency in environment, reliability and cost. And that’s all on our website as galvinpower.org and so I would certainly encourage you to look at that and if you have constructive suggestions or criticisms you may have about what that is. That’s been developed with a variety of different other organizations and we are jointly moving forward with this with Underwriter’s Laboratory which is our partner in moving this whole process forward.

And I’ll close by our book Perfect Power and I show that because this discusses this far more in-depth than I did. I didn't bring those books along but I did bring a stack of these Electricity Revolution which discusses some points I talked about here and gives examples of both the pluses and minuses in different states. And Perfect Power—one of the criteria that Bob said when we started he said, "Kurt, this is your business. You go ahead and do it. One thing I'm going to hold you to is do not set a goal of anything less than perfection. Because anything less than perfection will simply settle you for mediocrity." So perfection is always over your head but if you're not reaching for perfection, when I played sports my goal was to win every time, not win 10 percent or 20 percent. I didn't necessarily win every time but that was my goal and we have to have the same thing here. Perfect power service must be the goal and we must all be absolutely committed to doing that. That is the only way that we'll get this country back on the road to progress. Thank you very much.

MS. KELLY: Are there any questions from the audience? Quite rousing. We have one question.

MS. KOROSEC: Question from Stephen Davis. Stephen, your line is open.

MR. DAVIS: Hi. I'm Stephen Davis. Thank you, thank you Mr. Yeager. Quick question. Last year, the State of Colorado passed what’s called the Solar Gardens Act which I think is kind of in line with your thought process of enabling virtual ownership of solar shares of large solar arrays that are non-ambiguous to the property but within the serving area of your utility. What are your thoughts on the Solar Gardens Act?

MR. YEAGER: Well I am not an expert on it but what I do know is that it is definitely moving in the right direction and I’m glad to see that Colorado is now beginning to think about this and show some real leadership in this so that their experience that they’ve had recently is not left as an example that was a bit of a failure and so we want to make sure that all of these demonstrations are really effective. So I think they’re on the right track. And again, Craig Lewis, who’s been really active in Colorado as well may have some comments on this when he speaks this afternoon. Thank you.

MR. BROWN: Merwin Brown with the California Institute for Energy and Environment with the University of California. Hi Kurt. We’ve worked together many decades now and also share some of your vision on where this can go. The question though that I ask is that it seems to me we’re fighting a considerable inertia, that’s a reasonable inertia, which is the extent of the investment that is out there to move quickly with a standard net investment and secondly there's the economy of increasing returns where it's easier, cheaper to just keep patching the old system rather than get a new one. And so what I guess I'm trying to say is that the vision is perhaps the right one, how do you get there from here quickly? I don't see how you make the revolution happen without, so to speak, a lot of people getting hurt in the process?

MR. YEAGER: Well, it is a revolution yes but I prefer the word transformation. The people—I see no people getting hurt if this is done properly. And I don't see that the infrastructure that we have is rendered obsolete. This is not a matter of ripping out the infrastructure that we have. It's fundamentally about moving from analog to electronic control. And then to sort of pry open the door so that you can use the internet to send the information back and forth to consumers. So it is an opportunity. There is no real infrastructure that is lost. What we can do, though, is save on the amount of new infrastructure that we have to build because we'll get a great deal more capacity out of what we have and we will not have to build the peak generation. Right now with the economy down and the utility's infrastructure a bit underutilized but I think that when the economy does come back we have to start building new infrastructure and they’re going to be rate cases which become a political third rail. I think that will move to more consumer empowerment than we have seen. I think that there is no real danger to—and we’ve been demonstrating that in communities in this matter and communities are doing it. They’re doing it and then they’re not going out and getting a lot of extra money. They’re not necessarily getting DOE money. They’re doing it because they have the means to do it and as long as they have long-term financing then they don’t have to do anything to raise the bills for the consumers in the process.

Good. Well thank you so much for the time and the opportunity to speak with you. And like I said, I hope we’ve opened the door. Not that everyone will have heard or agree with everything that I’ve said but if I can urge you to think outside the box, challenge the status quo and I would certainly appreciate your critical feedback. If there are things that you really want to challenge, please do so. We’re not here for anything except to help catalyze progress for our children’s grandchildren. Thank you.

MS. KOROSEC: All right. We’re running a bit late and so to rather than dilute what should be a good inverter discussion with low blood sugar I'm proposing we take lunch now and return back at 1:00 for our second panel and we'll try to catch up in the afternoon. Thank you, everybody.

[Meeting resumed after lunch.]

MS. KOROSEC: All right. We're going to go ahead and get started again. Thank you, everybody.

MS. KELLY: Okay. Welcome back from lunch, everybody. The message for this afternoon is less is more. Try to really make sure that you look at those presentations and get to the points that you want to make so that we have time for some discussion to include everybody. Okay.

COMMISSIONER PETERMAN: And maybe efficiency is the right word to use. Efficiency will be key here.

MS. KELLY: All right. Good. This next panel that we're going to have here is going to discuss Inverter functions to support the safe management of increasing amounts of local DG and storage on distribution systems throughout the state. This is really an important issue that was brought up in a May 9 workshop here that having communications between the inverters and the distribution system was very important in Germany and in Spain and it's an important issue here in California. Frances Cleveland will moderate and introduce this panel. Francis is the President and Principle Consultant for Xanthus Consulting International. She has been active and served on standard committees and working groups with the National Institute of Standards, NIST –You’ll hear NIS mentioned enough to know what that stands for, National Institute of Standards and Technology. As well as the International Electro technical Commission which developed international standards. When you see these in some of these presentations you just have the abbreviation for that, the IEC, in front of all of those numbers. Frances?

MS. CLEVELAND: Good afternoon. It’s supposed to be good morning but it is good afternoon. We also now have six presenters where we started off with four. I’d like to start off with indentifying the questions that we were attempting to present on and then some discussion items that aren’t really presented but are open for discussion. So the first key one that probably most of the utilities will be addressing is what are the key distribution system operational challenges from high penetrations of distributed generation and storage including electric vehicles? The second part is there are a number of standards, won’t go into the details, but how or will the IEEE 1547.8 which is the new electrical connectivity standard in development, but how will that address interconnection standards challenges and what are the advanced inverter functions like the ones that are being proposing on the German grid codes. How are they being defined and what kind of challenges will those post? And what will the communication requirements be to make sure that all of this high penetration inverter based functions will need. So we'll also try to have discussion questions, because it always comes up, is the compensation for customers. If you're going to produce something other than watts. And then potentially get into some of the NIST standards, the five IEC standards, we'll see where that goes. Anyways, so those are the basic questions that we're being asked to sort of address.

And we'll start off with Bob Yinger of SCE. He is a consulting engineer, that's not a consultant, he's a consulting engineer working in the Advanced Technology Group at the Transmission and Distribution Business Unit at Southern California Edison. This group is responsible for researching and bringing into use new technologies for SCE. Bob?

MR. YINGER: Thank you, Frances. This afternoon I want to talk a little bit about some of the things that we're doing at Southern California Edison and working with a lot of others, actually, across the industry and sort of some of the things that we’re finding with inverters and high penetration of inverters because we actually are challenged with that right now. We have a program right now to put 500 megawatts of inverter-type photovoltaic units on our system and on our distribution system. And we sort of need to answer these questions now. We have an order of 28-29 megawatts of those commissioned and online today. And it’s growing.

But what I wanted to talk about was two areas. One is sort of transmission level impact areas and everybody talks about and you hear things about spending reserves and variability but there’s a second piece of it that’s overlooked which is how do you hook these things up to your distribution system. And I think that’s a really important piece and that’s the key issue that we’re seeing first and foremost on the system today because as you get more and more of these PV plants involved and they, a lot of times, show up in clusters on a small number of circuits.

We went through a program of actually testing inverters and subjecting them to a variety of faults, transients and other typical kinds of things you’d see on a day in a life of the grid. And how did they behave. Sort of the steady state questions are pretty well understood but those transient ones that, you know, in that one second or less type area are less well understood. We grouped sort of those issues we identified and those issues came out of the tests and some modeling we did after that. There's some protection issues, how do you protect the circuits electrically. And then there's the sort of engineering and designing issues which is sort of the steps you take before you install that system. There's the third area which is once you put those in operation. So what kind of issues do you encounter. And a little bit of a graphic here, and forgive the colors here, but we're looking for an easy way to identify which issues we think we've got issues around or things we need to do or things we need to get different answers to and then which ones we think going forward that we're going to have more trouble with.

And for protection issues that everyone is so worried about on the front end are probably not at the front end of our list in the areas of concern. We still do need to find out what our best solutions are around the overall circuit protection coordination. So how do you make sure that there's a fault on the little piece of the feeder or the whole feeder doesn't trip, only that little piece does, you look a little bit at if there’s an issue with reverse current flow. Many of our feeders that’s not a huge issue at this point. We do have some where we may have to look at that probably these are the longer ones and the more remote rural areas. What happens—what are the fault currents coming out of the devices? How does that affect your breakers and your breaker ratings and those kinds of things, so we need to look at that. Some of the testing we’re doing is helping us identify really how those inverters behave during a fault so we have good numbers for those studies. So when you have good numbers, you can do that studies. If you’re kind of just reaching in the dark, you’re in trouble.

The other two at the bottom of the slide, the ground fault detection. We know how to deal with that with other generators and sub transmission and transmission detection issues really are not a huge problem at this point because they are two way power flow systems in most cases today anyway.

From the engineering and design area, probably one of the chief areas we’re concerned about is around the voltage regulation on circuits when you have a lot of these devices out on the end of a circuit, actually if it’s a longer circuit with higher impedances, if you’ve got a cloudy day and that sun is coming and going, you’ll see your voltage winging up and down on the end of that circuit. There’s another phenomenon that we identified based on some papers we saw and some tests we did. But if you have an inverter generating at full power and you go over and you just disconnect it from the grid, the investor side of that switch might see as much as two-and-a-half times voltage for anywhere from one cycle to four or five cycles. That’s some that you can deal with but that requires some changes to the inverter control structure. So these are kinds of things that we’re thinking about. Is the case really there that we’re worried about most if you have, say eight or ten megawatts of generation on a circuit Sunday morning, you have one megawatt of load, car comes by and hits the pole, the wires are hanging over the street. Normally what we do is we go into the sub and open the circuit breaker on the circuit so that the crews can safely restore that power. If you do that, you’re isolating more 10 megawatts of generation with very little load. You might cause over voltages to all the customers on that circuit. So this is definitely one area that we need to look a little more into.

Communication protocols. And I know Frances is going to talk about that. I’m going to skip over that one for her.

Harmonic issues don't seem to be a huge problem. The inverters look pretty good, most of the ones we've seen. The one area—the one caveat to that is that we are starting to see frequencies that have pulse with modulation frequencies that are up in the 80th harmonic and higher numbers. Most power quality equipment doesn't go above the 50th or 60th so you don't even see these, you have to go looking for them if you know where to look. I don't think it's a huge problem but I do think we do need to start thinking about that a little more. Then there's the obvious design issue of conductor and transformer sizing which is something that you have to do for any generation or load on a circuit.

Systems operations. This is now once they're in service, we want to look at today we switch pieces of circuits around if they get too heavily loaded, we'll switch it on to a surrounding circuit. So now it's a little more complicated because you have generation out there that varies with time of day so you're going to have to plan a little better if I switch this piece of circuit over, you know pre-dawn, is it still going to work when the sun comes up or vice versa. If I switch it over during sunlight hours is it still going to work when the sun goes down.

We need to probably learn a little more on some of these larger inverters. We need to monitor those and again some others will address those.

Low voltage ride through is a transmission sort of problem but should be implemented down at the distribution system. And today's standards really don't allow you to do some of these things, the 1547 standard, so that's why when Frances mentioned 1547.8 is going to attempt to address those.

And then sort of the last one is remote switching capabilities. We may need to, for some reason, safety related or whatever need to section off some of those larger units. We know how to do that. We're trying to figure out how to do that at the least cost.

Inverter standards has been a major discussion and the volt VAR and the low voltage ride through are probably some of the critical issues. The original standard was developed around very disbursed units, kind of low penetration. Since we're moving beyond that, we go to the 1547.8 and when you start touching that, then you've got to go in and touch the underwriter's lab 1741 which is sort of how you certify and test 1547 and then you probably have to go in and touch California Rule 21 because it refers back to those other standards.

What’s our ideal inverter? This is a laundry list that we’ve been putting together. This is by no means final but we think it needs to help regulate voltage. We think we probably need some fast overvoltage protection so avoid those spikes when you shut the inverters off. And manufacturers can do that. It’s a software issue generally.

Fault current contribution. We need to come up with how we want that to look and again that can be varied.

Low voltage ride through. It’s probably with high penetrations that you don’t want to lose all of your generation at once. So you’re going to need some low voltage ride through.

Maintain the low harmonic distortion that we’ve seen in the past. And potentially be able to curtail power level remotely. This comes out of the German code, you’ll see that in there also.

Communicate in a standard manner to make it easier for us to integrate these into the system.

And then, the last one, is kind of an interesting concept. You want to be able to have these devices contribute to your system stability so if the voltage goes down you’d like them to maintain their power output and not have their power output go down when you most need it on the system. So you'd like them to help support the grid opposed to being a load on it at all times.

So anyway, that's a really quick overview of some of the things that we've found. With that are we going to go to questions or the next person?

MS. CLEVELAND: So are there questions?

COMMISSIONER PETERMAN: I have a couple of questions but I'm happy to save them for the whole panel though as all of the utilities might be able to answer them.

MR. YINGER: Okay. Thanks.

MS. CLEVELAND: Okay. So we'll move on to the next speaker. Tom Bialek whom you've already met this morning is currently employed by the San Diego Gas & Electric Company as Chief Engineer on the Smart Grid Team. I will leave it at that.

MR. BIALEK: Thank you, Frances. I appreciate it. So I get the opportunity here to talk to you again. Probably expand a little bit more about when I spoke to you this morning.

I think one of the key points from SDG&E's perspective is the need to get ahead of this issue as opposed to a wait and fix it problem. The existing energy feed-in tariffs for large customers that are installing one megawatt systems really have no requirements imposed on them. They basically interconnect, operate all they have to do is replace their meter technology if it doesn’t already exists. Some of the graphs that you see are one of those systems. So the real challenge here is when we think about—we like to talk about cost causation what does it all mean—as a state and as a utility that’s moving towards the future and we expect to see more of these devices the real question becomes what do we have to do. Do we as a utility actually put systems in place on our side of the meter? We can go out and buy equipment that Bob talked about and some of that equipment is available. And we can take care of that in a similar fashion as we do with capacitors today so that we can go invest in dynamic bar devices and potentially resolve a significant amount of issues. We would likely, in the end, go and do that and we could put it on circuits everywhere so now the question is that the best and most optimal solution so.

Same kind of things I talked about this morning. I’m not going to take a lot of time. Frances told me I had 10 minutes so.

Here’s a little bit more detail. Here we kind of get into more of these things. Voltage fluctuations and protection, operation, forecasting PV levels. I mean this is sort of alluded to a little bit in the morning but because it is an intermittent resource, a variable resource, the big key from an operational perspective becomes how do you forecast these things. What's the output going to be like? Both from an operational perspective but also from a capacity planning perspective. And I did kind of touch on the impacts on CVR. I know because this keeps coming up in presentations I've been involved in where consultants come and tell us if we just keep reducing the voltage everything will be fine. We'll have lower losses and more efficient systems. If you were to actually look at what these PV systems do at the end of the meter, they actually raise the voltage. And so the effect is even though you've put in place systems to actually operate under the 120-114 at the meter you're now being forced out of that range so there's some inefficiencies there.

Power quality, harmonics, flickers, load violations, kind of interesting but Bob talked about it as two-and-a-half per unit. That would likely be in form of violation and for those who don't know what that is that's basically a sort of industrial computer electronics standard that manufacturers are designing to. Now that's not to say that that one violation might cause the equipment to fail but multiples would likely cause them to fail. And then issues around utility safety.

So I think to follow on what Bob said, we are doing a lot of different studies. We are concerned given what we've seen, and I'll show them again to you, but really what is going on from a transient perspective and being able to measure that because I think that really becomes the challenge here. If you were to go to the ISO and ask them today what is it that you're measuring or on transmission machine operators they'll tell you that they're measuring 60 metric values and they see how those vary up and down. Those are averages over a significant amount of time. That's the way that we've historically calculated it. I think that's not the only issue and so when you start looking, you start to see things and we start to see things and we start to get worried. And that's sort of where we are as we're trying to push this along. We don't want to wait.

So again same kind of data but here's multiple days of data. So the question is for any particular hour, how would you forecast this. And this is 10 minute interval data opposed to one second data which is what you saw before. Those curves look significantly different as you speed up the assembly rate. The question is how important is that? I think really the question becomes how important is the power quality ultimately to the end users.

Here's the existing Rule 21 so you've got these voltage trip settings. You come off and tell me how long you got. And you'll notice this greater than or equal to 106 but less than or equal to 132. That's in one operation. That's the normal operation software with no arranges. It's outside arranges that we provide service to our customers. It's also outside the VBR ranges. And we have looked at that from both a SEDEMA perspective but that does cause issues as well and flicker.

I mentioned this before but this is a really short version of the German PV experiments. I think while in general our systems are designed similarly one of the big fundamental differences between most U.S. companies and the German utilities, and maybe the European utilities for that matter, is really that most of these are prophase large capacity, large conductors of primary voltages, large service transformers with multiple customers connected to them. So we are nominally, you know, at 25 service transformers with 25-55 KVA. We're talking anywhere from 8-10 customers per transformer. In Germany for their transformers they're talking about hundreds if not thousands depending on how big their transformer is. They are obliged to provide coupling for the PV connection and 25 percent of the cost is imposed on the distribution company. And if they must cover the rest they will. They talk about how they don't really talk about it in terms of PV, they've got other means that they use to justify the project. They are not in any granular measurement of current. And, interestingly, you don't hear this too much but they do have voltage regulation issues on the secondary network. The same issues that we're starting to see. Low voltage, high PV output and signs of fluctuations. Their solution is, similar to one of our solutions, they need upgrades. From that, if you take a look at their experience and what they've done, they've got their new draft code and it's really looking at requiring PV systems to support the grid. And ultimately look at how the upgrades minimize cost.

Looking around dynamic grid support. So Bob talked about this.

Active power control and reactive power control. So today that energy metering, everybody has their own set of unity power factor, max power point tracking and they're pumping out as much as they can because they're incented to do that. That's what the tariff does.

So as we talk a little bit about what we think about smart grid and the future part of that answer gets to be what does that tariff look like and should you change the tariff. It shouldn't just be a kilowatt or per kilowatt hour tariff. Should it be a kilowatt hour and a kiloVAR? And basically can we have the customers remain neutral from the revenue perspective?

There are very specific requirements that are being in this code. These can all be programmed into your inverter and that's the beauty of the inverters. There's software behind it and as long as you know what to program into it, guess what, you can plug it in there and have it operate the way you want. And that's actually a good thing. We believe that, ultimately, from a smart grid operational efficiency perspective that's something we're definitely going to require. But we've also realized that there are various methods to provide that reactive support and so I'm doing more here than someone from the front office. There are various methods of providing those VARs but the key here is that you are now, as opposed to a single entity power factor controlling the inverter. They're now talking about quadrant control. So to the point that, I think, we talked about it this morning, we talked about dynamic pricing, dynamic pricing becomes key to having customers participate but you also have to have the appropriate demand response programs which we ultimately believe will ultimately be pricing based.

And then from a liability and safety perspective there's a lot of discussion around synchrophasors, discussion around commission-based maintenance. One kind of interesting thing here is that is weather integration forecasting abilities. As we move forward, you think about what you're really asking the grid to do. You're asking the operators to control the grid and respond to it and resources that are controlled by how much wind is blowing and how much cloud cover you have. And so the whole idea of weather station integration and forecasting abilities is part of the overall sort of smart grid perspective is actually very important. How can we couple energy storage?

All sorts of other technologies. We're looking at various things. One of the things I'd like to point out here is that we're spending a significant amount of time doing power quality field measuring and analysis where we are looking at one second data and tenths of a second data on certain circuits with PV on it. One of the other things, I think one of the questions is what are you doing, have you actually looked at anything. We actually just—we're in the process of signing a contract with General Electric to actually put in a dynamic VAR device or that one particular circuit where we do have issues and do evaluations of both modeling as well as measurements to see how well does that help us integrate that particular set of renewables.

I think in summary from SCE's perspective, and Bob talked about this as well, inventing rules and requiring modifications accommodate high PV penetration. If we don't do that we're going to be left with a scenario where it's all going to be 12,000 megawatts of PV and unity power factor and that's the last thing that we really need.

The draft standards can be like today. Actually field measurements and modeling are important. We really should leverage, it makes no sense not to leverage, less learned in all the European countries.

And then one thing as I point out here, and may make you scratch your head, when all these devices go off, they're all set to go back on at the same time. So now imagine that you have 12,000 megawatts of some generation device, it turns off. Okay. But then it also all comes back on maybe five minutes later, exactly five minutes later because that's what they're all instructed to do. So now the grids going to sit there and bounce all over the place. So the reality is that there's some additional functionality that actually needs to be built into the system and with that I will stop.

MS. CLEVELAND: Any questions for Tom? We'll wait. Okay. Our next speaker will be Jeff Berkheimer from SMUD. He is the Project Manager in SMUD's Research and Energy Group working on distributed generation and storage projects. These projects focus on the evaluation and demonstration of new generation and storage technology and how to integrate these technologies into existing distribution systems infrastructure and design. Thank you.

MS. MACDONALD: Thank you, Frances. My name is Rachael MacDonald and I just wanted to mention a little bit on the agenda change. I apologize for any confusion this may cause. We asked SMUD to specifically present on their PV inverter work and so we're going to have them on this panel as well just to have them speak on the next panel as well, on the POU discussion.

MR. BERKHEIMER: Yeah, so I heard less is more so I'll try to keep this moving along here. So basically from a distributed generation and specifically a storage and PV integration standpoint, for SMUD when you talk about DG we're basically talking about solar.

So most of this is going to be based around that.

The role of SMUD in PV’s future, we have about 20 megawatts installed today with a goal of 130 megawatts net meter by 2016. Last year we rolled out a feed-in tariff program that was very successful. We had a 100 megawatts fully subscribed basically within two weeks of opening the project. So that was really helpful.

Kind of forecasting forward what we expect our PV contributions to be on our distribution system going out, this just kind of shows going out to 2013 that we’ll have about 170 megawatts total.

Right now from a resource planning, an integrated resource planning, standpoint one of the scenarios we’re actually looking at is to have possibly 500-800 megawatts of solar. It’s not necessarily that this is the preferred integrated resource plan but it’s definitely something that our distribution engineers and the company as a whole have to look at and say how would we be able to integrate this quantity of distributed generation of PV into our system and what are the risks and rewards. Certain solar industry reports are talking about grid parity being possible within 5-10 years so the technologies are really going to come down in price. We have a total commercial rooftop potential of over

1,000 megawatts and our total brown field and green field potential in Sacramento is many times of our energy need as a whole.

This graph, I think you guys have seen quite a few times, but it basically shows typical PV production and then typical system peak production, especially for a utility like SMUD. We take good solar production but the problem is like most other utilities is that it’s sometimes like four or five hours before our system can peak. While that’s great, we would really like to find a way to bridge that gap and bring it more on system peak so that we can get the whole benefit of that generation. The bottom part of this is just showing some typical graphs from partly cloudy conditions to partly clear conditions and the resultant intermittency that some of these PV rays can have. So this really speaks to the nature of if you had high penetration of PV on your circuits, it’s not necessarily a resource that you can count on like typical generation. It’s something that you have to recognize that can drop off significantly in a short period of time.

Current expectations is of up to 50 percent of our PV system output can be lost within a minute. That would be devastating if you have half or 75 percent of a feeder load being served from PV production and it’s a short feeder and intermittency of cloud cover would affect a lot of your solar rays at once. Just as an example, 250 megawatts would result in a loss of 125 megawatts within a minute. Our resource planning requirements wouldn't be okay with this, this is too high of a level of production drop. And the minute-to-minute load fluctuations at SMUD are currently much smaller of down to 10-20 megawatts.

Correlation of disbursed large systems are not currently well known but SMUD is doing a lot of work right now of trying to study this. We've been installing a five kilometer grid of solar irradiance center across our entire distribution system and we're collecting 15 second data right now on it but just to kind of match that up with actual solar production data to get a feel for what is the correlation and coincidence factor from a drop in PV production amongst certain PV systems within our system.

The importance of variability. Like I said, this just kind of shows that when you aggregate multiple PV sites your variability is better or not as bad as an individual site but it can still be significant. Especially on a feeder by feeder or a substation by substation basis, it's something that we're looking at.

Near-term integration issues. Obviously

evaluating the impact of these variable resources on distribution feeder voltage levels. SMUD has all the same technical issues that you're going to hear from all the other utilities here. We're concerned about voltage levels probably predominantly but reverse power flow and some of the other things.

Validation of caps on capacity on feeders at 100 percent of minimum daytime load. Right now there's not a good common agreement amongst the utilities on what the appropriate penetration levels are. So a lot of the work we're going is going to determine is it 100 percent of minimum load and some of the other rules of thumb that you've heard of.

Identifying and testing appropriate mitigation strategies to accommodate higher penetrations on feeders. So this is really where the storage and solar forecasting components come in. Where can we allow higher levels of penetration about 100 percent if we can guaranty that we can control the ramp rates and kind of fill in the sudden losses of PV production with energy storage or some other technologies? Or curtail output when we know it's going to be a very intermittent production day to kind of minimize the voltage impacts when cloud cover comes through.

And then identifying priority areas and limits for PV on a distribution system. Obviously, there's going to be some areas where you don't want intermittent generation just because of the sensitive loads that might be in the area.

The medium term integration issues for the volt VAR system are obviously evaluation of the variable impacts on regulation requirements. Forecasting the error impacts on the ancillary service requirements and associated costs. And then your redesign of your distribution system as a supply source to volt VAR power system.

And then the next couple slides are actually the more interesting, I think, of the presentation. So this is talking about some of the specific demonstrations that we have going on right now. SMUD has a subdivision out in Rancho Cordova called the Anatolia subdivision where every single home, right now there's about 275 homes that have been built. It'll be closer to 600 when it's finish, but every single home has high building efficiency measures and solar arrays on their rooftops from 1.9 KW up to 4.8 KW. And in these homes what we're looking at is we know that there's certain times of year, certain times of the day that a net generator is actually sending power back to our distribution system. So what we wanted to do was go out with some storage demonstrations, specifically for the lithium ion batteries at both the residential energy storage level and also the community energy storage level and figure out how effective is it to use these energy storage devices to firm PV output through—from the intermittency and then also to try to do some smoothing, some renewables of energy time shift to establish how easy is it to communicate with these inverters at the energy source devices to change modes, to put it in from a peak savings mode to a firming mode. And if we're getting too much production and we want—we decide that we want to use these batteries to charge and kind of add some load to the system, you know, how efficient is that?

And then a second component to that pilot, which kind of goes along with the advanced inverter communications panel that we're doing right now, is that we're going to be looking at our ability to use our existing AMI communication infrastructure to talk to these inverters, which are behind the customer panel and customer meters, as if they're another distribution device. We want to know is it a simple matter of inserting a network interface card and sending basic signals to try to change the mode of the inverter to curtail output? And put it into standby mode? It's not a very clear-cut question among SMUD and some of the utilities that we've talked to as to whether or not these will be easily integrated to look like another data point on our AMI system or if you truly have to install a secondary communications system to talk to these devices.

And, obviously, that would allow you to talk to your generation and your storage devices as actively controlled rather than just a passive device on the grid.

The second demonstration that we're doing is with two half megawatt, zinc bromine flow batteries, and one of these flow batteries is being installed on that same Anatolia circuit. It's connected directly to the feeder, just above the entrance to that subdivision. The intent here is looking at we're going to contrast is it more effective and more efficient for the utility to try and firm PV output on an individual home basis with residential energy storage or on a community storage basis aggregating 8-10 solar arrays from homes or from the feeder basis here were we're actually going to be monitoring power flow on the feeder and controlling the device from that regard. Again, we're going to be looking at the ability to talk to the advice and put it in different modes, control it actively, have it possibly receive weather data, solar irradiance data and try to firm PV output from that versus actual monitored data. And then, obviously, the other typical use cases of peak load reduction and load shifting.

A project that SMUD has been working on, the second one, is the Sacramento Solar Highway Project. We’ll be building 1.4 megawatts of PV and concentrated solar along two different sites along the U.S. 50 corridor. In and of itself, that wasn’t overly exciting in the R&D arena but we got an augmentation to the grant were we’re going to be able to work with Sac On and A123 to test out some of their advanced inverter technologies and, again, the lithium battery storage system. So you can kind of see the bottom left here on the diagram a single DC bus going through a single inverter. The inverter improves solar harvest by a good 5-12 percent over the standard inverters. We’re going to be looking at using the storage and this common inverter to minimize the impacts of variability. Again, controlled ramp rates, voltage regulation, voltage sag mitigation and peak load shifting so this is just kind of another site location to look at for large scale solar and energy storage integrated in one unit.

And then coming down the line, some of the projects that we’re looking at right now and considering for future demonstrations are automatic voltage control technologies to mitigate volt fluctuations. This is back to the conversation of truly what does it do when you have these inverters that aren't going to be operating at unity power factor and can actively be providing VARs to your system to flatten and minimize voltage fluctuations. We really want to take a look at the benefits of less volt fluctuations versus the possible negative impact of having quick and uncontrolled, or less controlled, volt flow coming back on our system.

Voltage sag and swell ride through. Again this goes back to the discussions that we were just having about the German standards in transmission and that you wouldn't want everything just dropping off for momentary sag.

Over and under frequency ride trough and then dynamic VAR support. So these are—I think all of the utilities in the room have beat these issues or talked about these issues enough. I forget this was being recorded.

[LAUGHTER.]

So that's all I have today.

MS. CLEVELAND: Okay. Thank you. So now we're going to go on to a couple of companies that have been involved in some of the standards to try and address some of these issues. The first one is, and they're both virtual people, so we'll have to bear with that.

COMMISSIONER PETERMAN: I'd like to ask some questions of these panelists before we move on to them. Thank you very much. Just a couple of quick questions.

First of all, Jeff. I'd like to thank you for mentioning the PIER grant. Again, we are trying to do a lot of work in this area and I'm glad that we can be supportive.

My first question not only pertains to the appropriateness of the existing inverters we currently have or use in the state in terms of being able to have the characteristics of the qualities that were mentioned in a couple of presentations. But specifically to get at, will we have to upgrade these inverters and is that possible through a software change or are we required to change out the infrastructure going forward as we expect to have new standards in this area. And then about what time do we expect to have them and what does that mean for what we currently have installed? And then I'll just reference in particular Bob, your slide 8 that contemplated inverter characteristics and if you could just speak to the current technology.

MR. YINGER: Okay. Let's see if I get the laundry list right here on questions. We feel that today a lot of inverters do not have the features we want out there for high penetrations. Now today we're not generally at those high penetrations yet although we're getting close on some of our circuits. The good news, and I think Tom talked about it, is these are soft of a software driven piece of equipment generally. And you can, a lot of times, go in afterwards and make some modifications that don't involve changing out the hardware but putting in a revised version of code there. Sort of a revision of the software and get a lot of these features. One example we had is if you look at this overvoltage problem that went on for several cycles. We told the manufacturer and he said, "Oh. I'll send you a new version of code and it will fix that." We downloaded that and then it looked a lot better.

So I think the changes can be made over time so we have some slack there, a little bit, but as Tom also mentioned we'd like to get in front of this problem rather than start and then have customer problems we have to react to. So the more we can do now on the front end the better off we'll be in addressing these.

Did I get all of those?

COMMISSIONER PETERMAN: You did. Just an observation, as we're talking about inverters, we have the very small 2 KW systems on a house and we're also talking about systems that may be 20 KW on the utility side. And then on the characteristics and issues. Some of them seem to me that they would be more of a problem with the larger systems than the smaller. As you provide additional comments, it would be helpful for you to touch upon those different markets.

And then, my second question is related to Tom's presentation. You talked about the German grid code. Just looking at the quality of the code that you highlighted, I was wondering if you'd be able to speak to how different it is from our existing code and this might be something that Frances could contribute to as well.

MR. BIALEK: Sure. Well, what I tried to show in the end was for the actual algorithms that actually exist today and exist in inverters, they are pretty much driven by certain percent levels, again, as it's software driven. They'll monitor what's going on based upon those tables and decide what to do. Basically they're offline and how long they'll remain offline. What you're really asking the inverters to do in this particular case is be more of a contributor to trying to maintain the reliability of the grid as opposed to automatically tripping off to protect the inverter. So low voltage ride through is an example of where you're really saying as the voltage of the grid drops, if it's not corrected then ultimately you'll start to get large generation systems flipping offline. And so anything that you can do to present that, to the extent that that's feasible, is a good thing because they'll reduce—they'll help impact the potential for significant large cell back up. And so that's what these additional functionalities do. They're really trying to provide some additional capabilities for the grid. If you think about that, as I said earlier, if you install 12,000 megawatts of PV that has just simple unity power factor of on / off functionality and then when that happens, it's going to be a real problem. However, if it has this additional functionality then at least it can operate pretty consistently at what is required of these energy generators today. And to one of your points, ultimately from the size perspective, yes size does matter and so you can argue that the Germans actually control 100 KW and above systems. You can get to a point where you can say for the larger systems, I want communications, I want control, I want more functionality. However, what you can also say is for these smaller inverters, because they'll be a significant number of them, I want them to operate slightly differently from what they have in the past and you can incorporate some characteristics that actually allow them to be much more supportive of the grid on very local levels.

COMMISSIONER PETERMAN: Thank you. That was very helpful.

MS. CLEVELAND: Okay. So we'll now move onto the first NREL and then EPRI with respect to this. So Ben Kroposki is with NREL from the National Renewable Energy Laboratory. He manages the Distribution Energy Systems Integration Group at NREL. His expertise is in the design and testing of renewable and distributed power systems with a focus on photovoltaic systems and grid integration. He has served as Chairman of the IEEE 1547.4, which is another one of these standards and that was for the guide and operation, and he's also been involved with 1547.1 but today's he's going to discuss basically the draft process that we're working to go through 1547.8. So. I'll let Ben start talking.

MR. KROPOSKI: Okay. So let me know if you can hear me properly.

MS. KOROSEC: Yes, we can hear you just fine, Ben.

MR. KROPOSKI: Okay. Then I guess I'm going to need someone to start turning pages for me. Please go ahead through the next four slides. This slide is just to highlight the concerns that utilities have with high penetration of distributed generation. I think all the utilities know these pretty well so we won't go particularly into a lot of detail on these. Onto the next slide, please.

Okay. So inside IEEE 1547 and this is actually a series of standards starting with the initial standard 1547 gives interconnection request requirements for installing distributed generation on the grid. And these are pretty much a standard rule that utilities have adopted on how to interconnect distributed generation. Dot one gives us procedures around those and you can see from the dates on those, 2008 that 1547 was reaffirmed and that 1547.1 is actually up for reaffirmation this year and we're in that cycle. So every five years these standards must be revalidated and reaffirmed.

One step that we'll really get into today is of the current projects and one that I'll just mention really quickly is 1547.4 was just validated and approved as of last week. So that's moved from a current project to an actual standard. And I think if you hit the button one more time we have a couple of other standards that are in the works, .5, .6 and .7 but 1547.8 just started last year and I'll kind of talk about where we are in the progress on that standard. So go to the next slide.

Okay. So 1547.8 is really a draft recommended practice that looks at how to supplement the use of 1547. So 1547 is very detailed and is a very specific requirement with how to interconnect distributed generation. And as we've talked about higher penetration levels, there are things inside 1547 that don't always make the most sense for when you go to very high penetration levels. And so 1547.8 is a standard that's really looking at how do we identify what those potential issues are and start to make progress toward making the standard really more friendly for higher penetration levels. Next slide, please.

Really the intended audience of 1547.8 is looking at the utility planning engineers also there are federal agencies that use these standards. The equipment manufacturers because they really would like to have standardized requirements to build the products and then there's distributed resources, developers and owners. Next slide, please.

So right now, the way this standard is being designed is that it is going through and sort of reflecting the 1547 clauses. So there's specific clause requirements within 1547 and .8 looks at each of those clauses and then tries to develop methodizations on when you have high penetration of distributed generation how does the standard need to be adjusted. And really it's intended to make PV and other generation systems utility friendly. You heard from discussions from the utilities on where they see those ideas going and so they've been very helpful working with the standards organizations to get those implemented into the standards. And really, we're looking at how do we incorporate this advanced functionality into the inverters themselves. Okay. Go to the next one.

So just as a practice of focus in 1547.8 and you can see a lot of commonality with what has been discussed in terms of issues with high penetration levels and what we would like to see inverters start to be able to do. The topics deal with things like voltage regulation, the monitoring and communication aspect, how do you really respond to these abnormal utility conditions, what kind of power quality do you need, coordination with other certifications and installation guides. And the reality is how do you make sure that the distributed generation, when there's problems on the grid, is available to help out the grid because of the fact that there's such high penetration levels. Okay. Go ahead to the next slide.

So we've been working with EPRI and I think EPRI is up next to talk a little bit about some of the advanced inverter functions that they're planning on incorporating. And these are also getting addressed within 1547.8 so that we can look at what type of advanced inverter functionality is needed and how do we make the requirements for manufacturers to start building products that will conform with our standards. So this is set up for phase one. You can go ahead to the next slide.

This is kind of looking a bit further out in terms of phase two. But EPRI has done a really good job in terms of defining what the function should be and then trying to come up with a way to get these management integrated into inverter technology. One more slide here and the next one.

Just kind of a status of where we are. This one is on a pretty fast track and we're working with NIST who's trying to speed this standards process up as much as possible. We had a kick-off meeting basically a year ago and a second meeting where we had our first draft document in February. For the first draft document, we already had a 91 page sort of resource draft created. So we do have a working document that's starting to get a lot of discussion around it. We've planned on having our next meeting on 1547.8 the first week of August. And we're trying to push this through the standards process as quickly as possible, understanding that the standards process does require consensus and to get an approved standard it normally takes a few years. So it can range from a couple of years to five years which is about what it took us to get the original 1547 done. You can start using draft standards. And that's one of the things that I would recommend sort of that the community and especially California and the utilities take a look at which is what can we start to do now that would help us make this a better standard in the long run.

So with that I'm done with my presentation.

MS. CLEVELAND: Okay. Do you have any questions? Oaky. So we'll move on to then next EPRI. We have here physically Don Von Dollen from EPRI but the presentation will actually be made by Brian Seal. Brian Seal is the Technical Executive at EPRI and he is the manager of a project for inverter functions involving utilities, vendors, integrators including Germans who call in, believe it or not from Germany once a week or once every other week. So this has been a tremendous effort and Brian will tell you some more about it.

MR. SEAL: Okay. Thank you, Frances. Can you hear me okay?

MS. KOROSEC: Yes.

MR. SEAL: Okay. Great. I appreciate the opportunity to be able to share with you, I wish I could be there in person but travel limitations wouldn’t allow it, but if you could just go to the next slide.

Just very quickly the perspectives, I think I can make up some of the time and then save it for the question session, but just for perspectives that EPRI has to share really come from a broad spectrum of research with a lot of different utilities so we get to work with some that are already dealing with high penetration systems and aggressive RPSs and some of them who have none at all and very few signs of solar high penetration appearing in their area. Also, our work with the Smart Inverter Initiative turned out to be the right project at the right time and has engaged a large number of individuals and has enabled us through surveys and prioritization workshops that we’ve done to really gain a lot of insight into what’s needed from the utility side and also what’s possible from the inverter manufacturer side. And by really overlying those two, we were really able to, through this consensus project really come up with a prioritization list. So that's where that phase one and phase two list came from.

We have a dedicated research project or program within EPRI that is dedicated to distributed renewables integration. And it is of high interest and very much of a hot button issue for us looking at the advanced functionality of the devices but also a lot of system simulation, distributing modeling and simulation, so that before we even have these advanced functionalities built we can simulate devices that would have those capabilities and then model what their response would be on systems. Go ahead, next slide.

So the first perspective is that communication connectedness is key. We found that, particularly within the U.S., utilities did not have much interest in advanced functionality of distributed inverters unless there was a communication connection to those devices so asking what would you like those systems to do, how would you like those systems to behave when you cannot communicate with them there was not much interest. Basically the existing 1547 rules be quiet, disconnect if anything does go wrong but when you add the communication connectedness and the ability, or the authority, to reach out and reconfigure and manage those devices then immediately you end up with a long list, like the ones we've seen from Tom and Bob and Jeff, just this long list of potential functionalities that are of great interest. Next slide.

So we began our work thinking about communication protocols. We looked at the gap that was initially identified was the lack of standards in the area of communications protocols but as we began to move down that road we ran into this problem of lack of uniform functionality. It was sort of enlightening, at least for me, that in the metering areas and other areas where we had worked with communication standards the functionality or the capabilities of the devices were fairly well defined. What we found in this area of smart distributed resources is that all the vendors have capabilities that are grid supported. They all have communication capabilities but they all implement these things in different, generally proprietary, ways. So when you aggregate multiple sizes of system, multiple types of devices back to the system operator it's quite unusable. So we ended up coming back first and said the conversation we have to have is about common functionality. What are some of the services that could be supported by a wide number of devices in a uniform way? Next slide.

So a perspective here, and this is based on our demonstration projects and also on our extensive modeling work, and this is probably looking a little further down the road than the current problem that you face. We would suggest that distributed resources, particularly smart inverters, can become desirable distribution system resources. Not just tolerated in high penetration but actually beneficial because of their ability to respond not just to communication in the wide areas but also to voltage infrequency locally. Perhaps a little bit of storage mixed in but also demand response and together we believe these things can really provide, in the distant future, benefits to the systems. Next slide.

So just a point to throw out there. In the integration, the communication integration, which is certainly very lacking today does not necessarily have to be high bandwidth. So one of the most valuable things that utilities brought into this discussion over the last few years has been an emphasis on high performance and high functionality of the devices but not requiring high speed communication to perhaps tens of thousands or hundreds of thousands of devices in the field. The way the work has been carried out, that looks to be completely possible by having more autonomous behaviors that are really conferrable at any time but also manage their own affairs intelligently based on local frequency and voltage. Modes of configuration so that you can fast reconfigure large numbers of devices between preconfigured behaviors you can switch them from mode A t mode B in coordination with switching equipment with capacitor banks or other traditional distribution equipment. We would suggest that AMI and SCADA systems, of the kind that we're familiar with today, are suitable for integration of these types of devices sort of like we heard from the experimentation being done at SMUD.

So this is a list of key functionalities. We've seen several of these so I won't belabor this. Just one point on the asterisks. Some of these functions do have question marks tied to them where there are potential customer sensitivities and we talk about smart volt VAR management but inverters can only make VARs to the extent that there's overhead available so do we intend for them to reduce their watts generation in order to do VAR support. Certainly watt volt management would relate to that. Curtailment of any kind, really, relates to asking the question of what is the incentive, what is the policy, what is the owner of the assets reasons for participating in these things.

Certainly a gap going forward. Next slide, please.

Okay. And I think this is my last slide. So of course continued work is needed. And just teeing up a few things here, one I just mentioned. The manufacturers and the owners have to understand why their projects should be grid supportive. What's the value proposition for them? Standards work has to continue. We feel that we just scratched the service in this area. Most of the work has been at the table, not in the field, so there are question marks across the board regarding the way the functions have been implemented. The transient nature of their behavior. One thing that is very interesting, and it relates back to my initial slide about communications being key, the German grid codes did not presume communications in many ways. They worked very hard at identifying specific behaviors and then codified those by requiring inverters behave a certain way. In the U.S. what we see is less confidence in a specific configuration and instead an immediate need or an immediate interest in having configurability of those behaviors and then the communication connecting us back to the central office so that over a period of time we can perhaps discover whether there is a single configuration or behavior that really could be baked into a product out of the box that did the desirable function for its lifetime. Today, at least in the U.S., we don't seem to have any confidence that we know what those settings would be and maybe we could have some discussion about that. We see a significant gap back at the central office. We spent a lot of focusing on the devices themselves, how do we make inverters smart. How do we make them communication capable? But when we get back to the central office where we're trying to coordinate those behaviors along with the switches and capacitor banks and line regulators that we already have, there hasn't been much work in that area and we think that's been a gap. And then the last bullet there, we already had someone already mention there about islanding being may be needed with certainly high penetrations of traditional unintentional island techniques are more and more likely not to work with the smarter we make these inverters because a lot of these functions tend to seek frequency nominally, they tend to see voltage nominal and react to deviations away from that. More intelligent or more active anti-islanding techniques may be needed. And I think that's the last slide if you want to advance.

MS. KOROSEC: Yep, that's it.

MR. SEAL: Okay. Great. That's all.

MS. CLEVELAND: Okay. I'm coming over here to do the final presentation on this panel two. However Brian certainly covered many of the issues that I am going to cover so I will sort of take the opportunity to expand on some of the things that he said.

One of them is that when we developed these functions, we decided to use an existing IEC, that's International Electro-technical Commission, standards but expand it in order to accommodate these inverters which of course have never been modeled before. So these were information models, not models of the inverter, but information models and that has been a very successful process.

I'm just covering four key things. Why are inverter functions important. To some degree that's been stated over and over again today and so also then I'll cover some of the key inverter functions and 1547.8 approaches to communication and then just throwing in a possible approach for California, certainly it's just my opinion so that it can have tomatoes thrown at it and so forth.

Okay. So just to quickly recap some of the things that have been said about inverters. Why are they important? First of all they're used by virtually every single DER, distributed energy resource, including generation and storage. Any one of those that requires a conversion between DC and AC and even some that go AC DC AC. So they're ubiquitous. They'll be involved with almost every kind of source of energy. And in addition inverters are now software driven and so, as Bob and Tom were both saying, you can change the software pretty quickly and pretty easily. Much more easily than changing the hardware. That makes it very, very good for establishing something, testing it out, maybe changing things.

And as we've all said the manipulating of watts we can change the output of the watts. You can change the output of VARs. You can do the volt VAR control frequency watt control dynamic bridge support which means not only doing the low voltage ride through where you do not disconnect but you also counter against this low voltage so that that in of itself is going at an extreme amount of VARs in order to kind of capture that and hopefully not even allow a disconnect.

The key here is that inverters can sense local conditions such as voltage and frequency and respond with autonomous actions. As Brian was saying you don't have to have communication. Obviously, communications are useful. They can upgrade and update software and issue a particular command but you don't absolutely have to have them and Germany does not intend, at this point, to have them.

So I think I will just move forward on this because I think it is key from this discussion today that inverter functions are important in California. I think it will be absolutely critical to have these inverters be smart so that we may, in fact, have different things where these small inverters may never need communication and maybe the larger ones do. That's one of the things that we'll have to analyze.

So this is the picture that I think captures a lot of the issues related to communications. If you see there on the right hand side, you can have an autonomous system that is completely self contained. It is just managing things based on local conditions. On the local voltage that it senses or the local frequency that it senses. So this is very important and that's why it can do the autonomous behavior. However, if you want coordinate these better to understand what they're doing and maybe modify what they're doing in response to local conditions such as being close to a substation or far away from a substation or during the summertime or during the wintertime, then you do want to have more communication so that you have sort of a middle section that tells the inverter to change modes or to change what they're doing. And then you can have way over on the left, you can have the utility that may just even broadcast a command that says we've got a problem, everybody shut off. Or we've got a problem here, reduce your output by this amount. Or change the mode that you're in. But it can be a broadcast. It doesn't have to be a one-on-one, you can do the one-on-one with the larger inverter based systems but not the smaller ones.

Brian went through some of these. Were these are some of the functions that we've talked about. So in addition to the volt VAR functions, there are abilities to do remote turn on and turn off. I can limit the maximum output and to answer one of Tom's questions you can add a random delta time to turn back on that is part of the functions that have been described. So that they will not indeed bounce back on exactly at the same time. And this time window is also applied to many of the other functions so not all of them go into sending out exactly the same amount of VARs at the same time so that you can avoid a hunting possibility.

So there's also the modes. There's the volt VAR modes, frequency watts mode, volt watt mode. A bunch of them, including temperate VAR control, which is equivalent to a capacitor bank these days so you could even those in a similar way of capacitor banks. There's also the ability to be able to send out a pricing signal. It's vaguely defined at this point because nobody knows what that might be but the point is that you can send some sort of pricing signal and demand pricing response signal and have the inverter respond to it. It can also be done by schedules so that's an important thing. You can schedule for behavior so in the morning it does this and in the afternoon it does that and so forth.

So this is all captured now in the IEC 61850-90-7 standard which almost exists. It will be sent out by the end of this week to the IEC for standardization. It's already being implemented in Germany and Spain and many of the other European countries. And it can be mapped to different things like DMP or web services so it doesn't have to be just using what the 61850 which some people don't like.

This just shows some of the volt VAR modes, I won't go into it in great detail, but the point is that you can vary your VARs based on your voltage level. And, in fact, in the lower one you can see hysteresis so that if the voltage goes high toward the right you change the VARs and if it goes low toward the left you actually have a hysteresis there so that it doesn't have real jumps between them.

Dynamic grid support which is really volt VAR support in the yellow areas where you have excess—where the generation unit is expected to remain connected. So this goes against the 1547 right now but this is one of the things that we really do need to address that and change those requirements to allow some kind of dynamic grid support during these times where there's almost an outage but can possibly be recovered from.

This is one of the areas where the Europeans do have this sort of must stay connected low voltage zone. What you can see here is that the different colors represent different countries. So that not every country has exactly the same set of parameters for staying connected. This is why it's important to have the communications because it may say that it's valid to remain connected if you're in this particular environment but have a different zone area defined if you're in a different environment. Microgrid might have a different set of zones than might a system that's connected. It might be different for being close to a substation or for being far from a substation. In Europe, it's basically country by country because it's fixed and they don't immediately expect to have communications.

So, not to belabor the 1547, but it is the new electrical connectivity standard draft that we're developing. And one of the proposed ideas is that the communication requirements, which were almost nonexistent in the existing 1547, but that the communication requirements would be based on the sensitivity of the environment. This might be similar to the clusters concept that was discussed this morning where you have a group or cluster of inverters and you analyze what their situation is whether they're really sensitive or large or have a lot of neighbors then you would require communications and in other cases you might say, "Eh. It's okay." And not bother to have it.

I think that the key here is as everyone has been saying is that the regulatory and financial environment of the utility has to change in order to allow these things to take place.

So this is my stab at possible California approaches to handling this rather large amount of PV. It's basically the same as the European approach. We recognize that, indeed, there are differences. The European grid has low voltage grid lines that have 100s of customers on them. We have a handful of customers on each distribution transformer. It does make a difference. But there could be a sequence where we again approach it similarly to the Germans where we initially require autonomous inverter functions to respond to local conditions via preset parameters. And this would mean that there wouldn't need to be, initially, any kind of communications with the possible addition of the ability to broadcast the—to respond to broadcast or multicast emergency functions like on, off and things like that so that you really step into the water first. Do a lot of testing through lot of pilots on these and see then what you need to do. Do you need to change the settings? And if you do them first just do it manually but eventually you can do it through automated remote upgrade means. But I think that this will be a way of moving forward that is reasonable in the fact that the utilities will then have time to experiment, time to try these things out. Even if they start with inverters that all of these inverter functions are turned off. They start out that way but you can have them at least there and able to be turned one when necessary, that would be a standard.

So as I said, that is my personal opinion and I will be the only one to blame for it. Are there then any questions for any of us?

MS. KOROSEC: From the Committee? From the audience? Please come up to the podium.

MR. GOODMAN: Yes. I'm Frank Goodman with San

Diego Gas & Electric. And is Ben Kroposki still out there on the line? I have a question that would best be answered by him. Are you there, Ben?

MR. KROPOSKI: Okay. Now I'm here.

MR. GOODMAN: All right. Thank you. The question is this. We have a situation in the original 1547 where it was all or none. In other words when it went to the adoption points, like Rule 21, it was intended to be adopted in whole rather than in parts. And now I'm wondering with 1547.8, which we are anxious to try out in draft form, when it moves through the balancing process and becomes an actual recommended practice, will it also be intended to be adopted in whole rather than in parts?

MR. KROPOSKI: That's actually a really good question, Frank, and I'm not sure that I know the answer to that right now. So that's question we'll bring up in the working group. But since it is a recommended practice and not a standard, I have a feeling that we will be able to test run the different parts of that standards as they are developed with the idea that, you know, you may want to use the voltage regulation recommendations from 1547.8 and nothing else. So things like that. But I think that's a very good point and we will make sure that we get that addressed in the work group and have some language in the standard itself.

MR. GOODMAN: Great. Thank you, Ben.

MR. KROPOSKI: Thanks.

MR. BROWN: Dave Brown from Sacramento Municipality Utility District. This question is for anyone on the panel or Ben as well. Looking forward about 10 years after 1547.8 is a well established standard, it looks like it's well on its way to becoming one, do you see a world where the initial 1547 is sun setted and it's all 1547.8 or some blend of each and how will we know which one to use and where?

MR. KROPOSKI: So this is Ben Kroposki. Let me respond to that real quick. You know IEEE standards have a basically five year shelf life and then after five years they must be either reaffirmed or withdrawn or updated. I think the last version here of 1547 was reaffirmed with no changes, really for the most part, because that's still where we are in the industry. But with the 1547.8 being worked on I think what we'll see is a merging of 1547.8 and 1547 probably in the next go around of 1547 so I think there may be a little confusion but say 10 years from now there probably will be one standard that we'll incorporate all of the necessary requirements for the various levels of penetration of DG.

MR. MCALISTER: Andrew McAlister from the California Center for Sustainable Energy. Great presentations for what it's worth we like this direction and we think it's very necessary and really great for DG in general and great for the grid.

Question though from the consumer perspective, either on a small skill and net meter stuff or the larger systems which are obviously two different markets, as we push power factors one way or the other down and make them less than one to provide other grid services, has there been a thought as to what this means for rates and real power and how much it will impact the greatest customers. On the top end it's the contracts, that's obviously something that contracting can take care of, but on the small end we have residential or small commercial customers and it's all about real power and there's no real part of a tariff that deals with VARs. If you push it down a lot, you're obviously going to impact the real power that you're delivering and wonder if you've thought about the process for dealing with that. And really, how big of a problem that is. It may be on the margins and not that big of a deal but I'd like to get your thoughts on that. MR. BIALEK: Sure. I'll give it a shot. We thought, actually, a fair bit about what that might mean in the future. We talked about in our consumer vision and consumers participating with providing services potentially looking at a whole selection of unbundled services that customers can actually participate via by tariffs. And, ultimately, looking at it from a not just a kilowatt hour type of perspective but from a kiloVAR hour perspective. And looking to, effectively, trying to have them—you know if you've got inverters there and the grid needs support in a local area does it make sense if you're willing to participate to not even try to come up with some tariff that will allow you to participate and to help support the grid. And I think in the long term from SDG&E is that the answer is yes. We think that there is that opportunity. I think the complexity of doing so is going to be down the road but I think in the longer term vision that's what we're thinking.

(Speaker not identified): Hi. My name is Alan and I'm from East Bay Power. Actually I have question for the CEC. We thought a good approach was to bring a community wind turbine to the load or to the use but now for the CEC the current incentive program limits the first certificate of it. Does CEC plan to offer an incentive to (inaudible).

CHAIRMAN WEISENMILLER: That would be a better question for the renewable, we're looking at the renewable guidebook, and that’s going to be sometime in the next month or two. That would be a better question there.

MR. BROWN: Merwin Brown, CIEE. There’s been a number of factors addressed here today that somehow reflect inertia in the grid but I’ve not heard inertia addressed specifically. And I know there’s some concern about what some of these low inertia generators will do to the grid. And so I guess now I have an opportunity to ask an inverter expert one, can inverters be used in the way at least to preclude inertia problems such as low frequency osculation creation and mode change and all of this and someone mentioned also turning it to a support for the grid, can you use these devices to fake inertia and help mitigate osculations?

MR. BIALEK: So I actually was at a DOE European research agency conference and one of the German utilities and professors of some research organizations were actually talking about exactly that. The algorithms that they used to develop that that they have actually incorporated into inverters to provide that service.

MS. CLEVELAND: I can actually add a little bit if you remember the hysteresis cycle. That’s put in there by the Germans in particular because they recognized that as a problem. There's also, as I said, time windows for doing things with random—you know each inverter has a random time within the time window so all of these kinds—and there's some ramping and some other kinds of parameters that are in there in the functional requirements and specifications. Those are all meant to help with the inertia issue. It's sort of, like you said, it doesn't actually act like a real inertia but it can sort of help do that.

MS. KELLY: Okay. So that it? Thank you, panelists. Thank you, Frances.

Our next panel is on Publicly Owned Utilities Perspectives and Strategies to support the state's new increased renewable distributed generation goals and smart grid technology options. This panel will be led by Rachel MacDonald who is an Electric Generations System Specialist in the Electricity Analysis Division. Her background includes governmental affairs and policy for distributed generation, smart grid, renewable generation and distribution infrastructure. And before I turn this panel over to Rachel I'd like to acknowledge her help today in running this workshop, getting the materials ready and helping all around. So thank you, Rachael, I just really appreciate all of your help. And turn this over to you.

MS. MACDONALD: Thank you, Linda. My name is Rachel MacDonald and I apologize for the lateness of which we’re going into the hour. I appreciate the publicly owned utilities being here. I’d like to say I’m not a publicly owned utility expert. Having always worked with, primarily, the investor owned utilities was quite overwhelming to come into such a large and diverse group of utilities that have different populations, different regions, different loads. It’s amazing but I will say as to my involvement, mainly through the PIER Research contract which I’m managing to develop smart grid vision, working with the publicly owned utilities. I’m learning a lot. And I will say that throughout those meetings one thing is consistent from the POUs and that is the customer. Customer, customer, customer. All of them.

Through those meetings and the development of that work, I brought up this workshop and the Governor’s 12,000 megawatt goal and I had mentioned at separate publically owned utility workshop and the response was, “It’s a state policy. We should be there.” And so I wanted to extend appreciation for your coming and participating.

And so I do have John Dennis from the Los Angeles Department of Water and Power here. He is the—

I’m just going to do the intros and then we’ll just go into the presentations. So John is the Director of Power Systems planning and Development. He has 29 years of experience with power system design and construction commissioning and planning.

Jeff Berkheimer from SMUD, you heard from earlier, again as stated earlier we did ask SMUD to specifically come and talk about their PV inverter work.

And Craig Kuennen from the Glendale Water and Power is the Business Transformation and Marketing Administrator and smart grid project sponsor for Glendale water and Power. He has led Glendale’s smart grid updates and has also worked in system design and delivery for their public benefits program.

And, unfortunately, Steven Budget from Riverside had to leave. He was here to present and his presentation materials are available. He is the City of Riverside’s Public Utility Deputy General Manager. And he is responsible for the energy delivery function including engineering, operation and maintenance for T&D. He’s been with Riverside for 21 years and public utilities for 36.

And I’m just going to point out Anthony Andreoni from CMUA, California Municipalities Utilities Association, has kindly agreed to jump up if we miss anything. Interaction with Anthony today has shown that he is very familiar with all of his utilities that he represents and with that, Anthony please feel free to jump in and I'll go ahead and start the panel with you, John.

MR. DENNIS: Thank you for your time today. I'm John Dennis, Director of Power System Planning LADWP. As we indicated, we'll try to do less is more here as many of these things are repeats or items that would be redundant.

Just very briefly, some quick characteristics of the City of LA. We represent about one power generation of capacity or capability is about one tenth of the state of California. We had a peak load, of this last year, of 6,144 megawatts and collectively between our generating stations and our distribution stations, receiving stations we have about 200 different stations in our generating and transmission, distribution facilities.

The vision is, as many are, to operate the system as safe, economical and reliable for our customers. We are undergoing some significant transformations on our distribution side with an aging infrastructure dealing with our poles, transformers and stations as well as implanting the automation efficiencies and technologies that we have.

Just briefly we did this last year published our integrated resource plan, it's available on the internet, but included in there were some areas that were of interest with our combined heat and power goals as well as the feed-in tariff targets and goals for this next year. But we did this last year achieve 20 percent of our renewable energy in 2010 and obviously we're all focused on the next big leap of 33 percent by 2020.

Currently we have 350 megawatts of CHP in our system. Right now, with our distributed solar, we've got about 34 megawatts or so in local solar and that program is growing under the SB1 Solar Incentive Program where we'll have about 130 megawatts of customer installed PV by 2016. And then we'll have our feed-in tariff program that's going to roll out here in the next two weeks. We'll have that available as we're doing some pilot studies and then DG installations, literally, just thousands of installations throughout our system in various sizes.

I'm going to skip through these on the incentives. There are some things of interest in maybe the future but with regards to the smart grid implementation and what we're doing there. We began in December of 2009 actually we have many of our smart meters that had been installed, even back in 2002 timeframe monitoring our system. But we have a program there with using ARRA funds with a 10 years project focus. But we do have a collective, collaborative team working with the JPLUSC and UCLA and those four primary areas of customer and behavioral studies, cyber security, demand response and electric vehicles. And currently, we have about 20,000 fully functional smart meters that are installed in our system or throughout. With our initiative that we have underway, with our demonstration project, our design activities for this and our pilot demonstration will be completed this next year with construction and a variety of test beds at a variety of spots throughout our system that we'll be implanting and working on very closely.

The challenges, I just want to get through this, quite frankly this is the last page. This will take a minute of time because, again, many of these were already touched on earlier today in the presentations. But I have to say as I work with our operations folks, I really appreciate the brain trust here in this particular room because these are the very things that give them heartache so I'm glad to see that we've got industry and utility coming together, collaborating and focused on those things that really do have concern for them. And so I believe that one of the questions that was posed to us was what can be done and how can the state help in this particular form and format I believe is part of that answer, so thank you for doing that as these technologies are still under significant development and with that information sharing is kind of a forum and this is beneficial to the utilities as we share these lessons learned as well as what the needs are. We're seeing those very clearly in regards to emerging software, SCADA and standards development. No one wants to go and rip out the new equipment that you've just put in and have to put in additional equipment and certainly I believe that we're showing here, even today, that we're on the right track toward where we need to be going and meeting that need.

The next item is just the potential to expand existing generating assets and negatively impact the local economy. We're going to get the violin out for just a brief moment and that is we've been out there with our rates case with the last six nights, we've had six out of the ten public meetings, and last night we were working in one of our poorest communities and just a real concern that folks have among the cost of their power and the different mandates that are coming through with some significant initiatives in the power industry and really some of the poorest of the poor people that are there are communicating their concern that even though their cost may go up 40 cents or even $1, I committed to this one lady that I would at least share with you all this – that there is a concern from there and we need to be continually looking at ways that we can do these improvements and improve reliability and environmental stewardship but also be cost effective for the state of California.

In our responsibility, as a utility, as a municipal utility, we're a vertically integrated utility. So we have generation, transmission and distribution responsibilities. So we're going to maximize everything we can with this technologies so that our customers enjoy the benefits of that but also that we're accomplishing some collective goals here.

An excessive amount of DG. This is another one that is probably in the area of greatest concern and that we continue to come back to is an excess amount of DG, especially during the low load conditions, may result in problems controlling and operating the distribution and transmission system. And I think that's been hit numerous times here, even this afternoon, but those are on those days where there's those puffy clouds on a March day where you have a low load condition and that topped with the element of a negative growth at this point in time with our overall power system that we're adding on more DG, that I believe the area—and if we can perhaps there's another follow-up workshop to get a little bit more pointed toward the communication link of that—of how we—of the inverter technology and the communication link as far as curtailment and the economic indicators and the signaling to those people. If we just think about it, somebody is going to spend millions of dollars to put in this technology and yet somebody is going to have that master control, or maybe there's some autonomous control, or maybe there's some algorithm in there that we agree to but nevertheless as we're seeing in the Pacific Northwest with high wind as well as high hydro periods and curtailment, we see that challenge there as the independent owners of those renewable resources are struggling then with their performance tax credits. So how do they continue to make the money that they expect to but then we have control that we're curtailing them.

So I think that there's an element there that perhaps, to throw another challenge in the room, of what we're seeing and looking at and it gets—and it looks like we have the technology moving forward with the enabling technology but it's going to be that piece of perhaps it’s the economists that will now pick this up and take a look at this and ask how to make this work on the economic side. So we’re going to struggle through that but we’re going to work on that continuously.

Last one is with regards to numerous initiatives that are underway. Boy, do we have a lot of them. We’re working on the CO2 reduction and once through cooling and 33 percent RPS and our reliability standards but we’re trying to put those together in a very careful package. And so, again, this is where this requires careful planning, proper integration and the adequate central control and monitoring of our system. And, again, I just want to express my appreciation to some of the work that’s already been done here and communicated. I’m really excited about what’s coming out of this, especially as we talk about EPRI and how they’re mentioned in some of this communication connectivity and dealing with that, the adequate central control or how we ensure that we provide a reliable service to our customers. Thank you.

MS. MACDONALD: Chair Weisenmiller, would you like to do questions at the end?

CHAIRMAN WEISENMILLER: Yes, why don’t we do that.

MS. MACDONALD: Okay. Craig?

MR. KUENNEN: Well, thanks for inviting me here. I’m Craig Kuennen, Business Transformation and Marketing Administrator for Glendale Water and Power. We’ll start out with a little description of us. We’re a little bit smaller than LA. Our peak a couple of years ago was about 343 megawatts but anyway, we’re a small utility northeast of Los Angeles. We have about 88,000 electric and 33,000 water meters. We’re home to the Americana, Disney, Nestlé and DreamWorks. We are one of 33 publicly owned utilities. We were selected for a DOE grant for smart grid and received $20 million and we’re equally proud to receive a $1 million grant from the CEC last April to support that same project. We’re looking forward to working with ya’ll on that.

As far as my presentation, I’m going to look a little on our vision and then talk about our smart grid project and then finish up with what we’re doing for our environmental goals.

We’ve adopted what’s called the Smart Grid Maturity Model to guide us through our planning and implementation of the smart grid. I don’t know how many of you are familiar with that. It was developed by IBM and Carnegie Melon University and it basically takes smart grid, divides it into eight different domains and in there you have five different levels of maturity.

When we first took their survey of where we were in each of the domains, it was quite obvious that you could take that model and actually turn it into a set of goals and milestones and a strategic plan actually for implementing your smart grid. So that’s what we did.

We’re planning for the future. The one domain with distribution operations and so our three year distribution system vision is right out of the smart grid maturity model. We’re going to start to deploy initial grid monitoring and control gestures that are tied to our smart grid vision. They’ll be an emphasis on communications and the smart grid automation. And there’s the other lower level descriptors here like we’re going to have a damped outage for restoration, we’re going to do remote access management and things like that. I’m not going to cover each one because we don’t have a lot of time.

For our five year distribution vision, we want to have analytics and automation and control in place to operate across multiple systems and organizational function. Some of these are kind of vague so what we’re going to do is assign people responsible for each of these domains and then underneath that there will be people making sure that we hit our multiple milestones in the one year, three year, five year and develop detailed plans to get there. So we can then gauge our progress over the years.

And that's where we get to the distribution system strategy. Here are some milestones for the first year. The first one was to develop a business case for new equipment and assistance related to smart grid in at least one of our business functions. We did that with AMI MDMS. We did a business case back in 2008. It was positive. That was the basis of our grant to DOE and I'll just talk a little bit more about where we're at in that process. But you have to have cyber security. You have to be—every step of the way you're looking at cyber security. So every vendor you contract with needs to meet the NERC and NIST requirements.

Three year milestones. A minimum 70 percent of our system has distribution substation automation. Twenty percent of the grid has advanced restoration schemes and things like that.

Five year milestones. They just get progresivly—90 percent of grid operation planning is transitioned to estimation to fact based using the data we're getting from the grid.

In terms of our smart grid project, the $70 million project covers electric and water. I think we're one of the few in the country that are doing both electric and water at the same time. We did a proof of concept in April 2010. We've installed a citywide trail post Wi-Fi communication system and that's, right now, it's set up for AMI. It can also do other city functions. We have plans to expand that function to do distribution automation and the kind of communication things that were being discussed with inverters could fall within that.

We're about 85 percent complete with the deployment of our meters. We'll be done with the AMI part of our smart grid probably August or September. And then we're going to be rolling our customer programs, a number of enterprise computer systems and we're doing a distribution automation pilot.

Some details about our customer programs. We're right now working with a local company to put together an in-home display that will be rather unique. It will have multiple functions beyond just showing you what your energy usage is. We think it's something that customers will want in their home and they will use it. So we're going to be testing that and our plan—there's going to be free for every one of our customers so we have probably 73,000 residential customers and this display could also be used for small businesses so we're talking about 70,000 in-home displays we're basically going to had to customers and teach them how to use them.

The OPower web portal. Currently, we use OPower for our energy efficiency program. And that’s been going for about two years. It’s been very successful. The last two—we measured how much energy savings we were receiving and it’s four percent of 25,000 homes is a big number. We think once we—we were working with OPower to integrate that into our smart grid data and have a web portal that will be in place in August or September where people can go and get data from the day before and be able to look at 15 minute data, weekly data, monthly, data. However they want to dice it up and look at it. We have a number of different programs that we’re going to be working with them—that will be part of that web portal.

We probably could save three times the savings. We’re getting four percent sending the paper report out to people every two months. You give them more information, I think, we could probably triple that.

We have a thermal energy storage program with one-and-a-half megawatts installed so far of ICE Energy and ICE Bear Units. We’re talking with them right now of putting in another six megawatts. Now these are smart grid enabled so we have two way communications that we can change the setting on them. We can then use that as a way to communicate into the building and do DR stuff inside the building. There's a number of things that we're going to work with ICE Energy on that.

There's a lot going on in our demand response program that we're starting out this summer. And then we're going to be looking at experimental pricing programs after we get some data and things like that.

Electric vehicles. We just did a study. We're looking at 6,000-8,000 by 2020 in Glendale so that's a considerable load we have to look at.

Here's just some of the computer systems that we're putting in. And so if you look we're putting in Enterprise Service Plus. We're just finishing up GIS. And then an asset management, outage management, distribution management will be over the next couple of years. The others depend on how much time and money we have.

So one thing that you really have to think about here is that we talk about all these technologies but you only have so many people to actually implement this sort of stuff and so much funding.

Our distribution automation pilot—we're looking at—actually, we're starting it right now. It'll be finished by September next year. It’s limited to four feeders and once we get some experience there then we have a 10-15 year plan depending upon funding to do the other 111 feeders in Glendale. Technologies, like I mentioned, expanded Wi-Fi and other technologies that I Mentioned as part of the pilot. We have some other things that we’re doing on our distribution—we’re upgrading our feeders from 4KB to 12KB and just regular projects.

And then environmental—these are right out of the Smart Grid Maturity Models as well. So that’s our three and five year goals for that.

And that’s all. That’s what I have.

MS. MACDONALD: Thank you. Thank you, Craig. Jeff, did you want to—I know you just did you presentation with the previous panel. I just wanted to check in with you and see if you had anything you wanted to—

MR. BERKHEIMER: When we spoke, we didn’t realize that we were doing both presentations so we don’t have anything to say except SMUD is doing fascinating things and you all would be very impressed.

[LAUGHTER.]

MS. MACDONALD: Well, I do know that SMUD frequently participates in a lot of our workshops. And they do have a very active smart grid development program and that through my own coordination with your governmental affairs representative Tim Tutt, I do understand that you are providing comments. And then I'd just like to note in regards to Riverside and Steven Badget, still on topic of smart grid, they do have over 100,000 electric customers and he did provide me with a copy of his deployment plans and what they're looking at doing. I will just add that he did comment in his email that all improvements and investments they were looking to do were not rate based. And with that, Anthony, do you have anything? Okay. Questions. Do you have any questions to share?

CHAIRMAN WEISENMILLER: Yes. I'd actually like to do a follow-up on one suggestion. And that is, it was certainly good to pull people together today as we can discuss these issues and everyone's experience. I guess one of the things to think about going forward, again, certainly if we could provide forums for people who might find them useful. I know the PUC has Rule 21 that's very focused on the IOU part of the equation but certainly if we could help facilitate conversation among the POUs and the POUs and the IOUs. We'd certainly be happy to do that. So something to think about ways we can help.

MS. MACDONALD: Do we have any questions from the audience? Frances?

MS. CLEVELAND: Frances Cleveland from Xanthus Consulting. I guess one thing I'd be interested in is if the smaller utilities, well DWP as well, would be interested in these inverter functions presuming that the vendors are able to offer them? Would that be something that you would see in your future?

MR. DENNIS: I like the characterizations that you gave for the small, medium and large and I believe that there is a small level that does meet that but obviously that comes with the cost so that would certainly be the determining factor. But I do like your breakdown of what you've proposed there and the attributes.

MR. KUENNEN: I would say yes. Like I mentioned, we do have the communication infrastructure in place. We will have the computer systems to work with that kind of equipment. I mean we're not that large but we could have 8-10 megawatts of PV and the next opportunity here in Glendale.

MR. BERKHEIMER: Actually, one comment I'll make on the software requirements and the inverter requirements is one of the things that we're starting to see is as we're actually building these demonstration projects is not necessarily that the inverter or communication functionality isn’t what we would like it to but that the issues around cyber security and the communication protocols there, especially as the devices are going to be receiving real time signals out of your data already in that system, is a lot more complicated and complex than we originally anticipated in talking with the vendors. Especially manufacturers of the inverters and anyone who has onsite hosting for a utility dashboard or an operator dashboard. These aren’t requirements that are sort of front and center and being dealt with in the industry yet so communications is easy. Anyone can plug in a phone line but if the media that you’re transmitting is secure information from an ENS or SCADA system it’s not as easy as plug and play. And if the industry could start looking at putting themselves in the utilities perspectives and saying this device is going to be plugged in and we know there’s going to be all of these very strict cyber security requirements, building a protocol around that front.

MS. CLEVELAND: Okay. Thank you for that. On the cyber security, honestly that’s one of the areas that definitely needs to be worked on.

MS. MACDONALD: Thank you, everyone. Next we have Timothy O'Connor from the Environmental Defense Fund. He's here to present about their work on smart grid.

MR. O'CONNOR: Good afternoon, Chair Weisenmiller and distinguished audience. My name is Tim O'Connor. Thanks for sticking around until my presentation, I really appreciate everybody waiting to hear this delivery.

We've been working for awhile on looking at evaluations for the utility smart grid deployment plans that are going to be coming to the PUC in the next month. I think we've already sort of seen and started to read the first one from San Diego and we're starting to see reverberations associated with that. News clippings, people starting to take interest from the general public and the environmental communities, folks who are sort of nontraditional utility hawks are sort of stepping in and saying they're going to be spending billions of dollars in my service territory on new technology, I'd like to see how that could help me and what it is. How it could help me as a consumer. How it could help the environment. What it's going to mean? Also, we're going to be looking at the same sort of deployments happening in PG&E's and Southern California's service territory. I think we've seen that the public hasn't necessarily been entirely accepting of new technology as it's deployed at their house or in their neighborhood or at their utility.

So EDF wants to make sure of a couple things. One that the utilities knew that were were members of the environmental community, the public that was advocating on the behalf of the consumers, looking at these plans and rigorously evaluating them to see if they were going to make the grade.

We have the utmost expectation that the utilities want to make the grade. They want to perform well. They want to spend ratepayer dollars in a way that's going to deliver benefits to the consumers, to the environment, to a number of different interests and so it is remarkably difficult when you think of maybe we're going to be getting three different plans over the course of the next month. They're all going to be written by different authors and some sections of each plan will be written by different authors and different endpoints and different ways to characterize things and some including some things and some including other things and so how do we compare one utility to another utility to a standard. To a regulation. And so that's why EDF developed a tool to help do that and we're going to talk about that in a moment.

But first, who are we? What do we matter? We're a national environmental group. We have about 350 employees who have been working on issues in energy and the environment for a number of years. We worked on SB17. We weren't an original sponsor. We have been active at the PUC and the smart grid rulemaking process for awhile, since the original decision came out. In fact, some of our recommendations were incorporated directly into the decision. Most notably the ones on the environment and consumers and platforms for technologies and certain services to grow. We're very appreciative of that sort of incorporation and we've been really kind of working on scaling up out participation in smart grid across the country in this thread.

So the reason why we're doing this is that it's a GHG reduction strategy. It's a consumer opportunity. It's an economic opportunity. And I have slides in my presentation that we probably won't' go into here, they're at the end, so if anybody want to know why we believe that we can get 30 percent cuts in air and climate pollution or why we think we can get 25 percent cuts in on road transporter emissions that's included in the presentation.

It is important to note that the 25 percent number is just from fuel switching. Just from taking cars off the road and plugging them in. We're looking at the energy storage component to that and what that could still take. It's even a larger number.

The point of this panel today and today really, just in general, is looking at distributed generation throughout the grid. I have some high-level points that'll kind of get into of why we think and how we think utility deployment plans can be evaluated so that they can be delivered on this goal as well as a number of other goals.

We'll start with some examples. I realize that it's a lot of words and a lot of words on a screen for somebody sitting far away and hard for them to figure out. Some of this stuff has already been talked about today. Electric energy storage has the ability to facilities more distributed generation. We're looking at when solar power is at its peak and when demand is at its peak, we know that they don't necessarily match up if we can switch or at least move one to two hours of the generation from solar DG to what it's needed as the most we can start to facilitate more.

And I do think that one of the things that we've heard today is that you can have too much DG. Well, yeah, I think that's probably correct if we're going to be talking about impacts on the distribution system. But let's say that we have enough DG that we're able to take off a peaking power plant. Well all of a sudden it's not too much DG, is it? We really get some environmental benefits out of that and we need to be thinking about how we can reconfigure our system and how we can use a smart grid on the long-term and start to get some real environmental impacts. We think that the smart grid, when combined with a lot of the technologies that it'll come out with, can really lead to some dramatic environmental improvements.

And we're going to get into, in a minute or two, how we can measure that progress and that's really the high level point of my talk today. But really sort of looking here at the examples of demand side management and looking at demand response and having people being able to tap into response and demand side resources to change the fluctuations of the demand curve to then also respond to fluctuations in the distributed generation so that we can more easily balance our grid. Also, filing on electric vehicles as mini storage devices as opportunities to switch from emissions of combustible fossil fuels to—in the cars themselves to electric energy use and then the ability to act as localized storage for distributed generation that's occurring at houses.

So what’s the high-level observation here. Smart grid deployment can deliver, in our opinion, significant amounts of distributed generation more so than there is not. And more so than we thought is possible and probably more than we think is possible today.

And then, finally, a full scale effort to deploy the smart grid really is necessary in California. We’ve seen that from the utility deployment plans. We’ve seen that from the PUC who said they were envisioning on how to write the requirements for those deployment plants. And we’ve seen that really written into the decision on how those deployment plans should be written.

And so by adhering to that decision we think that the utility plans can create the opportunity for more DG to participate on par with other traditional investments. And when I say ‘on par’ I mean that it can become cheaper, it becomes first in line at the loading order, more readily we can start to see more cost effective pursuits than we have today.

Here’s the quick portion from the actual decision that the PUC came out with. And in there, obviously, you can see that there are two words that are underlined and that’s distributed generation. And so all this and some of the documents in my presentation go in the thread that we believe the PUC is saying that the IOUs in California need to pursue distributed generation, it must be part of their plan, there must be a comprehensive effort to deploy it as much as we can in a way that can maximize the environmental integrity or the environmental impact of the grid, the overall long-term abilities in the grid and there are a number of references to both the DG to localize generation throughout the PUC decision.

What we decided to do was create a mechanism to evaluate whether utility plans were living up to what we feel is a requirement by the PUC. So we came out with a couple of different goals; actually four of them to empower consumers, to create a platform for innovative technology and services, enable the sale demand resources, improve the environmental performance at that greatest level.

These are EDF goals. These goals track very, very closely to what the PUC said to require. PUC had 11 different goals the utilities have to file. We really chose to focus in on four. The way we did that was by creating a points based metric and so at the end of this month and at the beginning of July, we’re going to be coming out with scores for the utility deployment plants as to how we feel that they fare. What is their grade, compared to one another how are they making the grade and across different goals and throughout different sections.

These plans need to have a vision. They need to have a strategy. They need to have metrics that they're tracking their progress along the way. They need to understand where they are now and also understand the roadmap of understanding where they want to go. All of this is included in our document as to how to evaluate utility plans. But it's not just about getting a score, it's about identifying where utilities are able to go and do better. Where they've gone above and beyond. If they've created a comprehensive assessment of their deployment plan in a way that will allow us to understand if they're likely to achieve the benefits that are possible.

So if you look at the individuals section, and as we pulled out through the PUC decisions and as we look at all of the literature on the subject, we find there are certain aspects within each of these goals that facilitate or are related to more distributed generation. For example, in the goal of empowering consumers. These aspects, we feel that if they were truly subscribed to by utilities, they would lead to more distributed generation. And when I say truly subscribe to I just mean we have a vision about having more electric vehicles in our service territory. Or allowing more consumer technology in our service territory but a real integrated approach to getting more and comprehensive technology on the system.

How do we know if we're achieving these goals. Well, it's embedded in metrics. It's embedded in utilities tracking their progress toward certain aspects. So we're going to get into some of our suggested and the metrics of the utilities that are already agreed to in terms of tracking some of these things. But maybe what we'll do is kind of go through some of these goals, look at where said there's real opportunity here and then we'll finish up.

So, for example, we know that there's a goal and that it's a goal that's required by the Public Utility Commission that says "Utilities have to create a platform for technologies and services." They have to create a market for new technologies to thrive, for new business models to thrive. And so interoperability is one of those ways that we have identified as being a valuable approach to doing that.

And so we would describe interoperability as an open architecture that allows for the incorporation of the evolving technologies on both the supply side and the demand side of the meter. And so utilities have agreed, and we would think that all utilities should agree to these metrics and not just the ones in—not just the publicly owned ones, to report the distributed generation capacity and the distributed energy delivery to the system. So, for example, utilities have already agreed to in that framework to report on the number of the total capacity of customer owned or operated, grid connected, distributed energy generation facilities. So I would ask whether the smaller scale guys, when they say "We're committed to more DG" whether they're tracking this and whether they're reporting this to the people who are in their service territories. Whether there's a buy in to watching the growth of DG deployment and tracking and supporting it. And in plans and in decision making, understand that if there is a roadmap and a goal and a traction toward that goal, that there is going to be some sort of evaluation of whether either that goal is met or whether there is way to get more information or change the system so that we can have further progress toward that goal. Total energy delivery is yet another way to do that.

In the goal of demand side sales, the

definition that I would come out with of new commercial markets is that utility's deployment plans should allow for the growth of energy markets for aggregated small scale aggregated generation resources. This is something that the EDF has suggested, not necessarily something that the utilities have subscribed to, but a utility plan that is fully subscribing to the idea that distributed generation is important and something they want to pursue, it's something that we feel should be included in any utility smart grid deployment plan.

So what is a good metric for something like this? Well, reporting on the total annual electricity delivery from customer owned and operated grid connected energy facilities is one way to do it. Having the utility allow for people to access progress or historical trend data on this information could be tremendously important.

Finally, on the goal of environmental benefits I think that in the environmental community there is general agreement that distributed renewable energy generation is a good thing. That is leads to reduced greenhouse gas emission. More renewable energy on the grid as a whole is a good thing. In the reporting on the greenhouse gas intensity, both in CO_2 and CO_2 equivalent emissions, on a utility wide basis, it's something that a utility should do. Just aggregating the types of generation that utilities are receiving into fossil generation, renewable generation, and other sorts of energy imports or whatever—however they're receiving—those sorts of metrics can help facilitate larger scale distributed generation and can lead to a mutual reinforcing effort. And as we're reporting the amount of GHG reductions we have that are coming from our electricity generation. And as we're reporting how much distributed generation we have and people start seeing, as the consumers start seeing, the linkage we can start creating more of a interconnection between the utility, between the customers and between the people that are supporting smart grid deployment or have not yet begun to support smart grid deployment as they likely should.

So finally we have been working on a number of aspects outside of California as well. It's important to note that these plans have started of course receiving attention outside of our borders. People in other jurisdictions are looking, obviously, at what California is doing. Not only is the PUC work being looked at by other regulatory bodies but areas in, such as Charlotte or in Chicago or Austin, having active deployments but it's really only the tip of the iceberg.

And obviously what we're doing here in California, as we're maximizing those, we're getting more and more distributed generation on the grid. As we're tracking things such as environmental performance and we're reporting them to the people who are paying for it, ratepayers, and getting people in support of continued deployment of smart grid as it achieves more environmental performance that's only a good thing. And if we could mirror that, that would be quite an accomplishment. So thank you.

CHAIRMAN WEISENMILLER: Thank Tim for your participation. We certainly had the opportunity ages ago to have the opportunity to work with Tom, David and Zach and certainly major, major contributions in California's energy policy from EDF.

MR. O'CONNOR: Thank you very much,

MS. KELLY: Any questions? Audience? Okay. All right. Then we'll move along. The next presentation is on How Research Development and Demonstration can Help Advance Distributed Generation. Mike Gravely who is the Energy System Research Office, Office Manager will start off and be followed by Dr. Alexandra von Meier, which we know her as Sasha, and she will follow up after Mike. I do want to say that there are still 70 people on the internet to take part.

MR. GRAVELY: Thank you all for sticking around. So I just wanted to cover a brief review of the activities we have in the research area both ongoing as well as future research in this area.

The general focus is research that would help advanced distributed generation, research focused on distribution systems and research focused on how the distribution transmission system works together and how this research can help mitigate problems of the future.

PIER Program, for those who aren't familiar, we do research for the whole sector, it's also research on generation, but my office works on transmission distribution integration of the systems through all of those customer side of the meter. So it's basically looking at how we integrate all of these together, how the smart grid will work, how transmission distribution systems will work and so we are very actively involved in the distribution research and development.

For those that aren't familiar, this is an IEPR Hearing Report from 2007 and certainly Linda is very familiar with this chapter because she wrote it. We had a major chapter on distribution and there was some changes that were coming because four years ago we noticed the fact that the distribution system needed to change, it had to go from a one way to a two way system.

It had to adjust to a lot of system problems. It had to be able to adapt to different loads. So as a result of that, we started a pretty substantial distribution level research program to go along with that. Many of the issues that came up today were also addressed in that chapter as some of the problems we had perceived coming at the future from there. The other things that comes a lot is that we hear about the renewables. Of course, today's discussion is on the 12,000 megawatts of distribution. There's 8,000 megawatts of transmission renewables. This is a chart that shows pretty effectively, it's a DOE chart, but it shows pretty effectively how renewables wind, in particular, effects the stability of generation and you can see in the upper left and lower right how systems that like to run nice and steady will be required to run at a very erratic mode without alternatives. And, of course, our research has been focusing on the alternatives that can make that bottom right look more like the upper left.

And also solar has very large ramping rates both when it comes on in the morning and whether you do it distributed or whether you do it centralized you have similar problems. So even if we do put in 12,000 megawatts of distributed solar this performance characteristics will then be distributed out through many networks and many of those may not have the stability and the ability to handle this without challenges.

In general the research efforts we do are focused in three areas. One is that we look at the actual components. For example, in the distribution area one of the things that came out of the IEPR 2007 was the extension of the number of underground cables we have in California and so we've done a considerable amount of research. The problem with underground cables is you don't know if it's ready to fail, if it's going to work another 20 years however without a look so a lot of these systems were being replaced. We were asked by the utilities to do some research and see if we can come up with some ways of testing the cables so that if the cable is 30 years old we could see if it would last 20 more years and then we can do something about that. As opposed to replacing it and finding out once we pulled it up, there's nothing wrong with it but the one next to it may be ready to fail in six months.

So we have been doing some research. We're in a test phase and have come up with some creative ideas on how to test the cables and we've been able to do that. And like I said before there are projects out there now being tested by the laboratories.

So we do this across the spectrum of looking at components. Obviously the big issue has become integration. We've been looking at integration from the system level via the commercial buildings via the microgrid and the residential home. And then we've also looked at it from the smart grid, which we've talked a lot about today with the whole distribution systems and also the transmission system together. So you talk about a utility level or multi-utility level and look at all the issues that will address that.

Some specific projects of interest to this area today, and we also have---PIER program has an advisory committee that is chaired by Chairman Weisenmiller and one of the topics—we just had a large meeting in March and one of the discussion points in there when we asked about what their primary issues were, they were very clear to them now that distribution was a bigger and higher priority than it had been in the past and so as a result of that we've adjusted our research funding profiles and we've begun to address more issues. You'll hear a little more about that. The program with Sasha. We'll talk about how it's very relevant. It is PIER funded but she'll talk about it specifically and you'll see how it ties to how some of the issues have been directly addressed today.

Demand response energy storage and those types of things. Forecasting. We're starting to do those with the utilities and with the ISO to help in that area.

Vehicle integration. Electric vehicle integration into the grid has become—as well as PV and these have become a big issue so we're looking at different ways to do that. There's quite a bit of research ongoing in those areas.

For those that are familiar, California was successful, not as successful as we wanted to be, but pretty successful obtaining quite a few of the American Recovery Reinvestment Act. Of those, there are quite a few projects in here that are storage related, distributed related, meter related. So one of our challenges is to learn from all these systems and see if we can go advance it. Some of these are more close to commercial, some are more in developmental. And so we're going to be using this information to take the next step forward over the next two years as most of these projects will complete the bulk of their work.

The two areas where we have seen a lot of attention, and whether it's distribution or transmission, it's the same and that is the use of energy storage to address some of the mitigation of the renewables. And also the ability of using demand response. The Commission has about an 80 year history of working with demand response and a five year history of automation of that response. So what happens, surprisingly enough, we looked into this. It was originally planned for peak load reduction but when you automate systems we can get the system response in 30-40 seconds and it can last for 30 minutes or so, it begins to look a lot like a profile of energy storage. The interesting part of this is it’s about 10 percent of the costs for energy storage so we’re doing quite a bit of work, as you’ll see, in trying to mirror energy storage and demand response together for a unified process. The reason for that was that it could potentially drop the cost of mitigating intermittent renewables anywhere from 30-50 percent over what it would be if you went with the more high cost option.

We’ve also done research in specifically using, in this case, in using electric home air conditioning units for ancillary services. We’ve now looked at the industrial side as well as the commercial side. But we’ve been doing research for several years on how we can take demand response, interface with the ISO and make that a service other than peak demand reduction. Make it a service on call for responding to variations on the grid.

Looking at the future. We also have an advisory board that met yesterday. Smart grid infrastructure advisory group. We met with them and talked about different plans for the future to get some feedback from them. Again, distribution came out as being a top priority for efforts to do and this kind of gives you an idea of research efforts that we're working together with on the other PIER teams and we'll prepare an actual budget proposal for our research and development committee for later this year. But what we're trying to do now it line up the research funding within the top priorities within the state.

One area where we had a huge success and Merwin Brown is here, he's been involved from the very beginning of this, the synchrophasors. If you're not familiar with that terms, it's a high-speed data collection system that's used for transmission systems. It goes from what we have today, which collects data every four seconds, to something that collects something 30 times a second. We had an ISO representative yesterday at our meeting, while they were at a meeting in Canada, pointed out that synchrophasors are now being deployed throughout the whole country. California is recognized as the innovative leader of this technology and PIER was founding source for this technology to be so far along. The DOE is putting over $100 million in deploying these systems throughout the country. The western U.S. is one of the big ones. The big deal of the ISO is that they can see things on the grid before it happens. It can prevent outages. It can prevent disruptions. They have a much better feedback system for the information so they can get the information and respond before our problem occurs. When they go with four second data the problem has already occurred sometime before they even knew it happened.

What’s going to happen now in our future programs is that they’re going to be looking at using this kind of data at the distribution level. As we get more and more instability on distribution level, then you have this type of technology that allows you to manage the distribution system better.

We mentioned before that we have quite a big effort of getting together energy storage, as I mentioned, we have this Assembly Bill 2514, we have in our case more than 10 projects right now that are energy storage related that are funded through ARRA and so we feel quite a bit of activity. The key is to leverage all of that and come out with the best solution for California. One of the things that we’re looking at for both storage and our DR is to look at what we estimate the need in 2020 will be to meet the RPS. We have a new effort starting with Lawrence Livermore where we're using high performance computing to help us estimate the model of the grid and come up with some projects that we hope will give us some better insight and what kind of variation we can expect.

That was pretty quick but I think we're real behind so I was trying do that fast. I'll answer any questions I can, first, and then I'll introduce Sasha for the second presentation. Questions for me from anybody? Yes, sir?

CHAIRMAN WEISENMILLER: That's good, Mike. Thank you.

MR. GRAVELY: Thank you. Okay. So Sasha has done a project for us in the distribution area which we think is very relevant to today's discussion. It is PIER funded so she'll be able to answer any questions that you might have.

MS. MEIER: Thank you, Mike. I don't know if I can speak as fast as you do. I'll try. So I will tell you about an initiative to study the distribution systems to facilitate the integration of higher levels of distributed generation. It's also relevant to the increasing presence of electric vehicles.

I would like to start by really presenting a bit of a comparison and contrast between transmission and distribution which I'm hoping is conceptually helpful. As Mike said, one of the really successful PIER funded research programs involved synchrophasors whose purpose is to give grid operators a real visibility and diagnostic tool of what is happening on the system. And you might ask the question what is the analog of improving visibility at the distribution system level.

Distribution systems are laid out differently, for the most part, than transmission so you see at the lower voltage levels mostly the systems are laid out in a radial manner. There is great diversity in how these circuits are designed. Many different attributes that vary. There's also time variation and what happens is that loads on the feeders and balancers that are relevant, they're vulnerable to external disturbances. But yet they're also largely opaque to the operators responsible for them.

This is a list, that I don't have to go through, but just to give you a sense of there really is a large number of attributes that distinguish different distribution circuits and they vary not just among utilities but within the given utility's service territory. There's going to be different generation of technology, some outfitted with new SCADA equipment for instance and some older. And a great range of technical variables that will of course affect how easy it is or how beneficial it is the integration of a lot of the distribution generation might be.

I liked this cartoon which is if you talked to distribution operators, you know, they'll tell you that their job is to expect the unexpected and at the distribution level, more so than transmission, that you just don't know what's going to be next. This is Andy at one of the more rural jurisdiction. He's a distribution operator. Just to give you a sense of a lot of the technology people are working with today is really still analog technology. It's not quite the bells and distinction as it's a few years old but it's not quite the bells and whistles you see at Cal ISO for instance but we're talking about telephones and sending a guy out in a truck to operate, manually in many instances, some of the switches or equipment. And this wall map that shows all of the circuits and I hear chuckles and you might think that this is so retro but they're actually really good reason for this kind of robust analog technology. For one thing, you know that you're dealing with the most updated version of the map.

And it’s a very rich layered texture of information about the peculiarities of individual circuits. The point being that these systems are really data rich and there’s a lot of variation that’s hard to capture in a generic model. So you have information like if you send a guy out in a truck to open or close the switch you better send two guys. I always like to say well one woman might be able to operate the switch.

[LAUGHTER.]

So this richness of data, the variability and vulnerability make it very important to get detailed information about what is happening on individual distribution circuits. But we don’t have the technology in place to see what’s going on.

With respect to integration of distributed generation, what would utilities like to see. Well, they would like to have data about voltage, about power flow, power quality measurements. Of course, in a perfect world, we’d have crystal balls that would tell us not just what the sun is going to do in the next minute and second but what the customers are going to do in the next minutes and hours and years. And we’d like to have good, predictive models and models that usefully aggregate individual data.

The first item here is really the foundation for everything else which is to get physical data in real measurements. What you have on the majority of distribution circuits to date is SCADA systems but they’re not on the 100 percent of the circuits that may give you voltage and power data but not really throughout the entire length of the feeder. Usually at the substation level. You might have individual pieces of equipment that are instrumented but again not all of the points along distribution circuits that might be relevant. Capacitor banks might give you a reading. In the automatic metering infrastructure, the smart meters, might be enabled to give you—to give operators data about voltage for instance but that functionality isn’t always in place yet.

So additional sensoring modeling is needed to evaluate and anticipate the impacts of the distributed generation on different kinds of distribution feeders and the question is where do you start and how do you do this in a cost effective and reasonable way? So for instance we would like to know what resolution and time and space do we really need to have measurements. It’s not entirely obvious.

There’s talk about using synchrophasors PMU, phasor measurement unit, at the distribution level. That might not be for the purposes of measuring voltage angles but it might just be for the time revolution of having 30 measurements per second for instance. It's not clear that you need that kind of resolution everywhere but we probably need to start with getting some high resolution data so that we then know how to scale back so we don't miss anything interesting.

Also, you've heard for instance mention of having telemetry on photovoltaic installations. We'd like to know well, ok at what level would that be really beneficial. Of course, the flip side of that is that you don't want to inundate operators with excessive data. So the advisory committees to the PIER research program have really produced, I think, a consensus that some of the major challenges do reside at the distribution level. That we do need increased monitoring and characterization of the distribution systems. And, as you also heard today, there's an impressive array of work already going on among the investor owned utilities and the POUs doing really careful studies of the impasse of distributed generation to date. There's also a sense that a collaborative coordinated effort would be really useful so that we can get data that is compatible and complementary and we can get a coherent big picture and a real systematic understanding of the great variety of the distribution systems that we have in our state.

So for that kind of comprehensive standard our initiative is really looking at starting from the characterization of some sample feeders and assessing the impact locally of distributed generation to then find a way to share that information and analyze the data in a coordinated way to inform then the next step better models of different kind of distribution feeders. Perhaps there’s a way to develop a typology of different feeder characteristics that’s meaningful rather than having to do a one off analysis for every single one but also as you heard today one single connection standard, for instance, or percent penetration cap might not be the most reasonable way to direct the use of DG on different kind of DG feeders since they’re so different. So we need to understand that better, what the impacts are and then see where do we most intelligently direct the efforts to do more sensing and monitoring and how do we, next step, tell the inverters what to do. We’ve heard that the technological capabilities are there but we, at this point, need to learn more about the distribution system so that we know what to ask of the DG technology.

Where I see—and I think the role of peer research is really important here as a coordinating function to bring together the common ground to make the collaboration among the individual utilities that have done specific technical work. But we want to have a coordinated effort so that people can learn from each other and don't reinvest the wheel. And that we really accelerate the learning process. So I'm going to skip through this as you have the handout but where we're at right now is forming a working group with technical experts from the different utilities to really hammer out the nuts and bolts of how do we, most intelligently, get the data together and have an efficient mechanism for collecting and evaluating these data.

Where we want to get to is clearly safe and reliable operation of distribution systems with increasing DG and also electric vehicles and, as was said earlier, it's not just a matter of tolerating the DG but really using those assets to the system's advantage.

Transmission operators, Cal ISO would also like to know a bit about what's happening behind the substation as the percentage of the renewable generation increases and that's a little harder to predict as it's distributed. It becomes important for Cal ISO to see behind the substation.

So briefly, being able to tell inverters what we'd like them to do so they can be of the most use to the system. And then finally knowing where the most important places are to upgrade distribution infrastructure because, clearly, you're not going to take down this whole—these assets and replace them tomorrow. We want and need to go step-by-step in a sensible manner to enable the most effective of both penetration of the distributed resources of where they make sense so it's a matter of finding the right places, the most beneficial places for sighting them but then also diagnosing where the issues really are to target the upgrades and the increased sensing monitoring. All of this starts with getting the data and seeing what's going on.

I would like to just finish on a personal note. As a graduate student I stated to take courses in electrical engineering because of my personal conviction that our country needed to go to 100 percent renewable energy and I realized that the biggest hurdle for that was probably in the electric power infrastructure which is why I began to study that.

I think as advocates of renewable energy we mustn't kid ourselves to say that this is going to be easy. I think these are some really difficult problems but they are also exciting problems. And I think they're solvable as we've heard today. So it's matter of smart people working together and I've been very impressed by what I've heard today and it makes me very hopeful. So thank you.

MR. VILLARREAL: So I don't have so much as a question but I'm going to make a statement. I actually have to leave at 4 so I'm going to make two additional statements if that's okay with the Chairman.

CHAIRMAN WEISENMILLER: Sure.

MR. VILLARREAL: Thank you for the presentation. A lot of what I've heard throughout the day is about how do we collect information, how do we know what's going on. One of the things that I failed to mention, because it didn't seem important at the time, was that there's a clamor for doing metrics and the PUC is in the process of finalizing a decision to outline how the utilities are going to start collecting and reporting exactly the things that were being discussed. And the requirement right now is to have the metrics be recorded annually starting in 2012. One of the things will be a continuous process on how to update, evaluate, revise and edit metrics as we go forward and as we get more and more information on distribution, what other information can we start measuring. What other information do we want to start measuring? And how do we do that in a cohesive manner much the same way that was just discussed?

So the PUC is a bit on the smarter side and much more aware of these issues and is very much supportive of continuing to collect information that will help support future planning for the grid.

The second thing that I wanted to point out is that I wanted to support a statement made by SMUD earlier on. Don’t forget cyber security. As we’ve gone through in developing policies, cyber security keeps coming up over, and over, and over again. As I’m sure Frances can attest to when FERC had their hearing earlier this year on the first five families of standards, 61850, amongst others, was hammered for not having an adequate cyber security review. So as we’re talking about standards, don’t forget that cyber security will still how up—and come out of nowhere that there is a clause somewhere in the standard on cyber security.

And the third thing that I just wanted to briefly discuss was that we have an ongoing storage OIR and we’re having a second workshop next Tuesday. So as a lot of the storage discussions are held here we also are having an OIR going on at the Commission. One of the things that is going to become difficult, but very important, is how do we value all of these benefits that solar provides. Those are the facilitating distributed generation, firming up the intermittent renewables and other grid aspects that we're expecting in the future. How do we help support all of those to make storage more cost effective? So these are our questions that we're going to be addressing in the OIR over the next—over the coming years. So I just wanted to say thank you for letting me speak up today.

CHAIRMAN WEISENMILLER: Sure. Thank you for your participation today. I think some of these were challenging issues that the two Commissions are trying to grapple with. I tend to be worried too that the cyber security is, whatever the right metaphor is in terms of the—we can't have a repeat of the smart meter—the PG&E smart meter debacle at least and cyber security could be one of the areas that could blow up in us in that sense.

MR. VILLARREAL: And we're very aware that in San Bruno the safety aspect of cyber security is also very relevant.

CHAIRMAN WEISENMILLER: So again, thanks for being here.

MR. VILLARREAL: Thanks.

MS. CLEVELAND: Actually, this is not so much a question for Sasha but she may answer this as well.

But this is related to the cyber security issue, there is a DOE funded NIST project that is—well it's being run by Energy SEC and EPRI is also doing some of the technology. I'm wondering is there any way that there can be involvement by the CEC, a lot of the utilities are involved, but involvement by the CEC with respect to trying to handle the cyber security issues? It's an open question.

CHAIRMAN WEISENMILLER: It's an open question and certainly one of the things that we have to grapple with on some level. We tend to be more involved on the R&D area here. The PUC is more involved in the implementation. Actually the ISO may be more involved in the operations of trying to figure out the best way of this combination. But, again, trying to work in a complimentary fashion.

MR. GRAVELY: So I wanted to point out that we do have a Smart Grid Center that we work with at Sac State and there's a specific element there on cyber security who has been working with us and been following the PUC rulings and helping us provide information and helping us update the Commission on where we are. So it is an issue that often comes up. It is an issue that we are following from the research center and helping to get information for the policy side. But we're very actively involved with the PUC efforts and we are tapping the expertise that we don’t have in-house that we are suing from the Smart Grid Center specifically for cyber security.

MS. KELLY: Thank you, Sasha. Our next presenter is Craig Lewis. He is from the California Clean Coalition. Craig and the—the Clean Coalition used to be called the FIT, the feed-in tariff, no coalition there. But whether it’s the FIT or the Clean Coalition, one thing is for sure that they at every interconnection meeting that I’ve been at, going over weeks of meetings at the ISO last summer at the utilities, the Clean Coalition has been present and active and adding to the discussions. Craig is the Executive Director of the Clean Coalition, an organization focused on implementing best practices for scaling cost effective clean, local energy that is available now throughout the U.S. Mr. Lewis is a leading smart energy strategist and advocate with over 20 years of experience in renewables, wireless and semiconductor industries. He founded the Clean Coalition in January of 2009 and has navigated the first successful solar project through the California Renewables Portfolio Standards Solicitation Process. And he’s been involved in two dozen RPS projects since then.

MR. LEWIS: Thank you, Linda. Chair Weisenmiller and everybody else, I know this is the end of a long day—or coming to the end of a long day. So I'm going to try to be very brief with my comments. I've got a lot of details in my slides. Those slides are available to everybody on the website so I'll trust that you all can navigate through the details as you wish.

Per Sasha's comments that she just made, she was really impressed with the slides that she's seen today and the presentations. I also have been very impressed. And the conclusion that I have at this point is that I've worked in the DG market for a long time. I've been involved in dozens of projects through the RPS program here in California and the DG market is ready. The market is there.

What I'm convinced of after today is that the smart grid technology will be ready by the time it is needed. It's not needed today, we can put lots of additional wholesale distribution generation on the grid before we actually need the smart grid solutions to be active. But we need that technology to be on its way and it is on its way, as evidenced by everything we've heard today.

The, probably the most important thing

relevant to this—my presentation here is that the policy is broken. So we've got the markets there, the technology is coming but the policy is broken. And that's what needs to be fixed. The policy needs to be fixed in order for us to maximize success of the potential of distributed generation and smart grid solutions. And it's a big part of what needs to be fixed is with respect to interconnection. We need lots of interconnection reform if we're going to be able to get anywhere on seriously generation smart grid.

This slide didn't actually come through very well. A couple of words on the Clean Coalition. This is a slide that I made six years ago and it basically is what we need to do—we need to get from the energy picture that we have today, and we have the energy picture six years ago. That's my chart there on the left which is a fossil fuel dominated energy picture. And we need to get to the smart energy feature which is the—what's supposed to be a pie chart there on the right. And that is supposed to be mostly green with renewables, demand response, energy storage, electric vehicles and everything surrounded by energy efficiency. Those are the big five solutions and those big five solutions are almost are related to DG and/or smart grid.

A quick note on our Board of Advisors because we've got a strong connection here to the California Energy Commission. Two former Chief California Energy Commissioners are on the Board of Advisors— John Geesman Jeff Byron and also lots of other names that are very familiar to the Energy Commission here.

So let's put California into perspective. The situation in California is that we got an RPS program back in the early 2000s and we've basically been flat lining on the technologies that are actually of any concern here. The technologies that are of concern are the intermittent renewables technologies, that's solar and wind. Well, California has basically been getting lapped by the leading markets around the world that are actually deploying solar and wind. And California, relatively speaking, is just flat lining. So California is pretty much the horizontal line in green toward the bottom and you see markets like Portugal and Spain and Germany that are just lapping us. Their curves are exponential in comparison.

So I talked about the fact that the policies are broken and they need reform. This is a look at the experience that California is having with getting wholesale distributed generation online. Or excuse me, just getting wholesale renewables online. And what this group of bars represent, if we just look at the group of bars on the very far right that represents the experience for the amount of renewable capacity that is getting fed into the RPS solicitation process and the auction processes. Any program that deals with RPS energy, this is the—the top blue bar is the amount of energy that gets bid in to those programs. The aggregate amount. And what happens is that we lose 90 percent of that right away between bid capacity and what actually gets shortlisted. And I can tell you, I’ve been involved with dozens of projects, you spend an average—even for small wholesale DG projects—a couple o megawatts—you’re going to spend anywhere from $300,000-$500,000 getting your bid ready and 90 percent of those are gone. You don’t even make the shortlist. So if you don’t have any opportunity to negotiate with the utility to bring that energy online. Now the guys that are lucky enough to get shortlisted, the 10 percent, half of those—or more than half of those don’t actually get to the contract. And this chart doesn’t even go into the fact that probably half of those projects that get contracted never actually come online because they bid too low or their interconnection costs end up being too high and they go away. So we just have a really, really damaging experience here in terms of failure rates.

We’ve got to fix that.

One of the ways to fix that is to follow the leading markets around the world and bring a clean program; a clean, local energy accessible now program which is essentially a feed-in tariff for the wholesale DG market segment.

So just to make sure that everybody is clear on what wholesale DG is, this diagram basically shows three market segments. We’ve got the retail DG market segment and everybody knows that. That’s the net metering market. And then we’re got the, on the other side of the spectrum, we’ve got the big central station renewables. It’s out in the middle of nowhere, 100 megawatts. It’s interconnected to the transmission. In the middle is the sweet spot and it’s really what we’ve all been talking about today. It’s the wholesale distributed generation market segment. It is renewables that are interconnected to the distribution grid and serving local energy needs.

All right. So let’s look at the markets that’s actually working. Here’s a little comparison of the solar experience in Germany versus the solar experience in California. The Germans are putting on 28 ½ times more solar. In 2010, the Germans put on 28 times more solar than California did despite the fact the California had a solar resource that is 70 percent better than Germany’s.

Now that next thing that you need to see is that the Germans are doing this, it’s almost entirely rooftop solar, they put 7.5 gigawatts of rooftop solar on in Germany last year. Rooftop. And you can see how it’s distributed in project size. It ranges from residential scale up to over a megawatts scale—but almost all of the deployment are one megawatts or smaller rooftop solar projects.

And by the way, I just want to note that these are mostly not behind the meter. So this is wholesale DG. Interconnection directly to the distribution grid. Even if it’s up on a residential rooftop it comes down and interconnects with the distribution grid. One hundred percent of the energy is delivered to the grid and they’re paid for every kilowatt hour that’s delivered.

All right. Sometimes people will say that the Germans are paying too much for their solar. The reality is that they’re paying the equivalent of 12 cents a kilowatt hour. This is for rooftop solar, in Germany, today. And those efficiencies is because they’re doing so much deployment that they can get the scale where the cost of the equipment, the cost of the installations and the cost of the financing are so low that basically 12 cents kilowatt hour is what they have to pay. Now some people will say that it’s actually 30 cents if you do the translation of the German feed-in tariff rate. That is actually true but if you take 30 cents and you convert it for the fact that they don’t have the tax benefits like we do in the U.S., they don’t have the solar resource that we have in the U.S.; 30 cents in Germany is only worth 12 cents kilowatt hour in California.

And this is just a quick slide to show you the different in the solar resources in Germany versus California. The German—the country of Germany is in the lower right hand corner. Purple is the worst solar profile that you can get. It’s worse than Alaska. The entire continental United States is better than the solar resources that they have in Germany.

So I’ve talked about the interconnection issues. This is a chart that basically shows the number of interconnection requests that we are now experiencing in California and you can see that we’ve had this massive ramp up of interconnection presence. This is for distribution grid interconnection requests. And the actual amount of energy and the number of projects that have been connected to our distribution grid is practically zero. Almost all of the renewable energy sign-ups in California for the RPS program has been central station, interconnected to the transmission grid. There's a handful of projects only that have been connected to the distribution grid. So barely any projects that have actually come online but there's a whole bunch of backlog on interconnections. But why is that.

Well, we have, as you heard earlier this morning, we've gone through this interconnection reform process. Well we definitely need interconnection reform but we need to re-reform the process. What is basically happened is that if you want to interconnect to an IOU territory, that' PG&E, Southern California Edison or SDG&E, you're basically looking at a process that is going to take you two years just for the interconnection. So this chart is a little hard to read but if you've got a copy of it in front of you, you can see that the orange bars show you want the total process is. The process steps involved with getting a project online with an investor owned utility in California. This chart shows that it's basically going to be between three and three-and-a-half years, that's if everything going according to the calendar so who knows if that's going to happen.

What I want to emphasize here is that we have a really good example from the Sacramento Municipality Utility District. Those guys have a process that gets the interconnection done in six months. Six months versus two years. The IOUs and the regulators in the state of California have got to do some benchmarking off of best practices. And Sacramento is providing a beautiful benchmark for providing interconnections done efficiently and effectively.

So I'm going to go over a few points. This is kind of what I call the connecting the dots to reform. There's a lot of really important pieces of information that's spread out in a lot of different places. I've got my top five in place here for you.

The first one is that 75 percent of investor owned utility's capital expenditures are spent on the distribution grid. Just let that sink in for a minute. Three-quarters of all the investor owned utility's capital expenditures are spent on the distribution grid. This is a massive investment not being made by the utilities, it's being made by the ratepayers. It's being made by me and you. That is a massive investment and as a ratepayer I want to make that my investment is being made effectively. That means it needs to be future proofed. It needs to be ready for lots of wholesales and DG to get interconnected to that grid.

Second point, Germany and Spain provide excellent proxies for California’s distribution grid to accommodate significant loads of clean local energy. There was a great KEMA study that was commissioned by the California Energy Commission that was just released last month and it showed that California’s distribution grid is not all that different than Germany’s or Spain’s. And the Germans and the Spanish have multiples, multiple, times more distribution of wholesale DG on their grid than California does. We’ve got a lot of headroom before we need to hit any panic buttons. And we need to start getting that energy. We need to get those interconnections done.

Third point. Market price reference. This is kind of the standard for what you’re allowed to sell renewable energy to the utilities at in California. The market price reference is determined at the point of interconnection. This means—and it’s off of 500 megawatts combined recycled gas to room power plant. This means that that interconnection pilot is out in the middle of nowhere interconnected to the transmission grid. When you normalize the locational benefits of interconnecting your energy to the distribution grid instead of the transmission grid, you’re talking about a

25 percent value add for the energy interconnected to the distribution grid is worth 25 percent more. How do you get that? Well, first of all you’re not paying transmission access charges which are at least 1.5 cent per kilowatt hour. That’s just the supposed standard rate that has to get paid. For every kilowatt hour that drops down from transmission to distribution it’s 1.5 cents, that’s about 15 percent of the baseline market price. Then you take into account that there’s a line loss and a congestion loss for every kilowatt hour that comes off the transmission. And on average that’s about a 10 percent line loss, line slash congestion loss. So there’s a 25 percent value boost to wholesale distributed generation in California that is not valued, that’s not compensated at all, in the market price reference. And we need to change that.

Last two connecting the dot points. Developers are responsible for 100 percent of the cost of distribution grid upgrades when they interconnect projects to the distribution grid. This is different from how it works on the transmission grid. On the transmission grid the ratepayer is going to pay 100 percent of the upgrade cost of the transmission grid. And they’re going to pay zero percent of the upgrade cost for the distribution grid. It’s just the way FERC has ruled on these things. So the ratepayer is getting a free upgrade to the distribution grid when developers are interconnecting to the distribution grid and paying for network upgrades.

The final point here is that the wholesale distributed generation interconnections need to be far more timely and transparent. As I already talked about this, wholesale DG interconnection process is basically that you're looking at a two year process if you're trying to do interconnection with an investor owned utility in California—And I also mentioned that we've got a beautiful benchmark with SMUD. SMUD did a 100 megawatt feed-in tariff program, 100 megawatts of projects, and they took two guys in two months and did all the interconnection studies for all of the projects that were in the 100 megawatts. Two guys in two months. And it takes two years to get a single project done with an investor owned utility. I know there's investor owned utility guys in the room and a lot of them are my friends, but that is really pathetic and we've got to change that.

All right. So the solutions. We need to re-reform the distribution grid interconnection procedures, I hope that is painfully clear to everyone. We need to create a robust clean program, a clean local energy accessible now program, which is also known as a feed-in tariff program for smaller projects five megawatts and below is what we promote. And we need to implement a D-grid vision, we have to have an integrated vision for the distribution grid.

One of the important things here is that the California Public Utilities Commission is proving to be a lot more friendly toward making sure we're getting good quality interconnection reform from them than the Federal Regulatory Commission is so to the extent that we can we need to make sure that the CPUC is in charge of interconnection policy instead of having the Federal folks in charge of it. We really need to reassure jurisdiction over wholesale distributed generation interconnection and we should do that through Rule 21 interconnection reform.

And both FERC and the CPUC need to hold the utilities responsible for making sure that they are doing their interconnections on a timely and effective and transparent process. So we need to have audits because right now the utilities are in charge of the interconnection processes. You have to go to the utility to get your contract and you have to go to the utility to do your interconnection. And there's nobody auditing them on the interconnection. We need audits and we need to make sure that those audits are moving the investor owned utilities to the benchmarks that we’re seeing from the really good—the folks that are have really effective interconnection processes like SMUD. And we need to have penalties. We need to have some teeth in that if the utilities don’t perform. There’s lots of penalties for the developers if the developers don’t perform; we need to have some venalities on the utilities if they fail to perform.

All right, I’m going to skip that slide. And I know everybody is getting a little tired so I’m going to skip to my next big topic which is that we need to have transparency on what the upgrade costs are going to be. So I told you that the developers are responsible, and I’m on slide 21 for those of you following along remotely, the developers are responsible for 100 percent of the upgrade cost of a distribution grid project. A project that’s going to interconnect to the distribution grid. These constants range from zero to million of dollars per megawatt. So these things—it’s like playing a game of Russian roulette and, like I said, you’ve got to go to the utilities and deal with the utility in order to know what that cost experience is going to be.

We’ve got to get some transparency on those interconnection costs before a developer gets site control costs of hundreds of thousands of dollars. So before you start that process of getting site controls, you need to know whether that location has any kind of potential to become a viable project. In order to have transparency you need to know things like what's the capacity. What's the capacity of the substation that this location is connected to? What about the actual circuit and the line segments? What are the back feed potentials and the cross feed possibilities at that point? Keeping minimum loads of all of the items above and the size of the location in the queue. Not only do you have to have a snapshot of what it is today but you have to have a snapshot of everybody that's ahead of you that's going to be interconnecting wholesale DG projects anywhere near you on that circuit or that substation. You have to be aware of that because that's going to impact the experience you're going to actually have at the end of the day when you finally get it built.

You need to be able to predict what those upgrade requirements are going to be and determine what the costs are going to be, ultimately that is the most important thing. What are the costs going to be?

Now here's a little bit of good news. Data availability is improving. So we've been working—the Clean Coalition has been working for a long time with lots of other folks and the CPUC has been very helpful in this effort and I think the utilities have been very good in terms of coming along and, particularly, PG&E has really led the way. They provide a fair amount of data availability now. The problem is—there's still a problem that the data that's available doesn't allow you—it's not the data you need in order to qualify for things like fast track which is an accelerated interconnection process. You don't have the visibility that you need in order to know whether you can qualify for things like that and if you're not in fast track then guess what, you're stuck in the two year long process that I was talking about.

The next two slides basically show a table, and I'm not going to go through the details, but what they'll be showing here is a partial list of the things that you will have to pay for upgrades. These are a new transformer or some reconductering of power lines. There's a list of things and as you need more and more of those things on the list you're experience is going to get more and more expensive in terms of the network upgrades. So what we need to do is we need to start standardizing some of this. So data availability, when I talk about data availability it's not just how much capacity is there at this point and how many people are ahead of you in the queue but if you decide to interconnect a five megawatt size project at this point what are my costs of network upgrades going to be. Rather than playing a game of Russian roulette tell me. There information is there. The utilities have this information. They know that if you interconnect five megawatts at that point you're going to be tripping a transformer and you'll have to connect some lines and let's make that information available. And we can standardize this process. We can standardize the costs.

So this is my very last slide. Basically, we're standardizing and rate basing for preferred locations. So if we can standardize this process then for locations that make the most sense for the ratepayers in California we should also allow the utilities to pay for those upgrades which would simplify the process drastically for interconnection and if the utilities are paying for it, then eventually, that's going to be rate based so essentially the ratepayer is going to pick it up. But if we do this it will streamline the whole process and we'll have a much easier, effective and successful experience with the smart grid and distributed generation in California.

MS. KELLY: Are these any questions from the audience? Nobody? Okay. For our last presentation, Eugene Shlatz is a Director in Navigant Consulting's energy practice. Gene has over 25 years of management, consulting and supervisory experience in energy delivery and power generation systems. He has managed to include smart grid and renewable technology, asset management, electric reliability and systemically he was used for the U.S., Canadian and South American utilities. He is an expert on electric power delivery systems and has testified before FERC and the State Utility's Commission on system expansion, transmission open access and retail rate cases and regulatory compliance. Today he will discuss a study that he did for the Public Utility Commission in Nevada and he looked at the costs associated with adding DG to the distribution system from the distribution utility's point of view. Gene?

MR. SHLATZ: Thank you, Linda. Thank you everyone for your patience. It's four o'clock so we'll try to run through this fairly quickly and what I'll do today is focus on the most salient issues in terms of why this study was done, what the outcome was and what are the key results, what are the key impacts, what is important, what's not important and from there entertain any questions that you might have.

Okay. Just a little background. The Nevada Commission issued an order to the company to examine how much DG can be installed on the existing system. And the important point to highlight is that they were interested in the system today with no improvements and what can the system accommodate. Some concerns were being raised by the company that well if we see too much PV there could be some impact, there could be some cost and cost was certainly a concern in the economic climate in Nevada. We were interested in the performance, is there enough capacity available on the system and also what's going to be the impact on electricity rates seen though the predominate issue was that how much DG can we fit on the power system.

Our focus folks looked at the 80/20 rule, let's not spend a lot of time on what's not important but take a look at where they are likely impacts. We found out that a good portion of the system was fairly benign in terms of the impact of DG on the system so we tended to focus more on those areas where there could be impacts.

Just to emphasize it again, we looked at DG meaning PV and wind, typically five megawatts or less and, in most cases, less than 50 KW, a lot of it rooftop PV interconnected at the primary distribution level, 25 KB or 12 KB. I should mention that we are currently conducting another study where we're looking at large PV and DG interconnected on the transmission system partly as a result of this study which found out their impact on the power system so the two systems were integrated. We'll devote more time to that later.

It was a collaborative process. We got a lot of good input from a fairly large stakeholder group involving solar community, wind community, state energy office, and the public service commission of course, the company. And, in fact, all of our assumptions had to be vetted and approved by this stakeholder group which was selected by the Commission and incorporated into their order. We found that they provided very, very good input along the way and the process of everybody providing their view and everyone having to sign into or vet all of our assumptions was very critical to get everyone to agree with the results of that study.

A few details look predominately at renewable, a small PV, a relatively small wind. It's about a 70/30 split overall between PV and wind in the north, 90 percent PV and 10 percent wind in the south. The north predominately being the Reno area. The south being predominately Las Vegas.

And techniques which were used were very detailed simulation models, distribution load flow models so we could assess the real or the likely impacts rather than back of the envelope type calculations. And we also used production simulation models to be able to evaluation the impacts on the power systems, including generation.

We looked at three scenarios over time, one percent penetration, nine percent penetration, 15 percent penetration over a 10 year period. What we found was that the one percent penetration scenario really had minimal impact although we jumped very quickly to the high penetration scenario at 15 percent. A little over 1,000 megawatts on a 6,000 megawatt system. That roughly translates into your 12,000 megawatts in California. So the studies are somewhat comparable in terms of the amount of DG penetration. Again the 15 percent penetration pace is roughly equal to 10,000 megawatts or almost equal to California. I will emphasize again the one percent level, even at nine percent, we found that the impacts were so benign that we began to focus on the high penetration cases and, in fact, we began to look at penetration levels above 15 percent because in many areas of the system 15 percent DG did not create an impact.

Now what we had to do to come up with a proper representation of DG impacts and performance on the distribution system was to come up with a representative set of feeders in the north Reno and the south Las Vegas that pretty much covered a broad range of potential DG interconnections and feeder on their system. We wanted to make sure that we got the urban feeders, rural feeders, those with the mix of residential and commercial and industrial loads. Trying to focus on six representative areas in the north and the south for this detailed study. And I would highlight the loads ranging from one mile to 110 miles and loads ranging from about 1 megawatt to as high as 12 or 13 megawatts. Same thing in the south, relatively short feeders to somewhat longer feeders. All 12 KB. Downtown feeders, residential. And again we visited to make sure that we had a good representation so that when we did our simulation analyses we had an accurate representation of how DG performance would be of urban, rural, light load, high load.

And initially we looked at uniform distribution of DG meaning equally spreading the PV across all of the feeders. Somewhat of an idealist assumption but that was our starting point. If DG was uniformly distributed what are the impacts? But then we also looked at more realistic scenarios where if you take a look on the left, uniform distribution, for purposes of doing our analysis we lumped or grouped the

PV at 44 houses in this particular neighborhood on this particular feeder for purposes of doing—or streamling our feeder analyses. And then we also clustered the PV at the end of the feeder so that we could examine impacts under uniform distribution versus clustering all of the PV at the end of the feeder.

This slide represents our first display of performance results and what we found for the north and, this was a particular feeder, but somewhat representative of most of the feeders on the system. Assuming a range of plus or minus four to five percent voltage regulation, we found that under 19 percent penetration voltages at the end of the feeder were no lower than 98 percent well within the 95 percent criteria that we set among the stakeholders.

What we actually found though, in some instances, of their light load conditions voltage raise if a bit more of an issue so when you have a lot of DG located at the end of the feeder, light load conditions, we found that voltage regulation in terms of voltage raise became a bit more of an issue. And that's fairly consistent with the number of the studies that have been done independent of ours.

But under the lower penetration scenarios there was very, very little movement in terms of voltage regulation and that was partly due to the length of the feeders. Many of them are short in urban areas. Many of them are underground cable systems. Voltage regulation on those short feeders in a suburban and urban areas of the Las Vegas, and Reno for that matter, were marginally impacted from the voltage regulation standpoint because only 15-20 percent DG is being looked at. It was relatively benign, all inverter based, set power factor at .99 or 1.0 so it basically became a current injection source and direct offsets of the load. Hence, as a result, voltage regulation in most cases was not a problem.

Then e took a look at what happens when you take all of the DG and put it at the very end of the feeder or the worst possible location in terms of voltage performance. Then we began to see some results where it was a predominately raise issue, mostly on the longer feeders, recollect that we had a 50 mile feeder, a 100 mile feeder, so when we put large amounts of DG at the very end of the feeder there were some violations.

One thing that I would highlight though, if you take a look at this blue line, that blue line is a typical feeder in Las Vegas, serving a mix of commercial and residential loads. And, in this case, we had DG penetration levels of up to 80 percent of the feeder rating. Those one to two mile, mixed residential and commercial small industrial feeders have very, very low impact from a voltage performance standpoint. It’s only when you got to outlier feeders which were extremely long, not representative of these entire systems that we run into some voltage problems. And in the case of this particular feeder, this is, I believe, an 80-100 mile feeder where all the wind and PV was put on at the end. We looked at light load conditions under very heavy penetration, 60 percent, and it’s at that point that we began to see voltage regulation problems. In all cases though, at 20 percent—15 percent or less, there were no significant voltage regulation problems.

Now. So one thing that I would mention that I don’t have up here is that there were pockets where, recognizing that some of the lateral feeders, someone mentioned today putting a lot of DG on the number four overhead wire and it creates some localized problems, we saw that. But our primary interest was looking at the mainline feeders and whether or not there would be any major impacts recognizing that there was always a potential for localized problems. The local distribution transformer didn’t end up being big enough. The local distribution single line may not be big enough and those may have to be upgraded for higher penetration levels.

And so our essential conclusion on the distribution study was that the distribution system alone was not a limiting factor with regard to how much DG could be installed on the system. Of course, recognizing very high amounts of DG located at the end of the feeder might cause some problems with regard to voltage regulation, we also found that some of the protection devices and coordination items had to be updated. These are relatively low cost upgrades compared to the cost of rebuilding a feeder. So I don’t want to ignore some important findings with regards to the need for improved protection, protection coordination, changing out the old analog equipment were we can accommodate some reverse power flow.

So what we found though when we began to look at the volt power systems, in terms of OK. The distribution system has some minor limitations but by and large not the limiting factor. Then we need to look at the bulk power system. The combined generation system in terms of can you take 1,000 megawatts of DG and put it on a 6,000 megawatts system and still have your generation operate with current performance criteria. Recognizing that they have other large projects, large biomass projects, large wind and other large solar that had either approved purchase power contract or were in the negotiating stage. Forty-four projects outside of DG represents around 1,200 megawatts of other renewable generation that is likely to go onto the system where it exists today.

And that leaves us with this diagram. I've seen variations of this diagram today and so it's a little bit fuzzy but what we did was, we took every single day of April 2011 and basically drew the hourly loads for each of those days. And then we took a look at what might be a stressed hour and that is about nine or ten o'clock in the morning when there's a significant amount of DG output in the form of PV. Now I'll walk through this very carefully. At about nine o'clock in the morning, the voltage is between 2,500 megawatts and 3,000 megawatts on the entire power system. Recognizing that there is a balancing control area which is about a 6,000 megawatt system compared to about a 50,000 megawatt system here. So what happens? Fifty-four percent of that load is met by conventional thermal generation, predominately combined cycle because it can follow load, to meet operating reserves. But then we also have another 5-10 percent buffer because of proposed energy efficiency and demand response programs of up to 500 megawatts of demand response. The 1,240 megawatts of committed renewable projects all must take energy under the purchase power agreement and then the question becomes how much more DG can we fit for those hours. And in that particular hypothetical example, that brings us down to about 300 megawatts. And that led us to conclude during those hours of the year when loads are light, like this spring when loads are light on the system, we need to be mindful that the generation systems can be impacted and can possibly limit the amount of DG. So that led to a conclusion in our study that a more dominant factor was power generation system and whether that could accommodate this amount of DG, or 12,000 megawatts of DG.

We also looked at the cost impacts. We were interested in what—when you integrate that amount of DG, one percent, nine percent, 15 percent—what happens to the generation mix in terms of fuel offsets. What fuel is avoided as a result of DG. And their system was predominately natural gas but, interestingly enough, the blue lines represent avoided coal generation. So not only were the combined cycles being backed off but some of the coal generation as well. And that's because of the evening loads or the early morning loads were generation had to back down because of the DG and the renewables.

Now the question also came up of what are the corresponding benefits? Are there any capacity benefits for wind and predominately PV? And the Las Vegas area, which dominates the load, tends to peak later in the day. So we identified a good match or correlation between peak PV output and peak system output or peak load. So we found very minor capacity benefits associated with DG.

And nearing my last slide, another part of our exercise though was taking a look at current net metering loads which allows up to one percent of net metering, well what happens if we were to increase the nine percent or 15 percent? And what we found was that the upper dark shaded area represented the emission benefits associated with DG, the green-light green represented fuel cost offsets, the remaining cost in blue repents effectively all the remaining O&M expanses at the distribution level, distribution system investment. And so we found though that there was actually a revenue gap of about $50-100 million annually under the current net metering rule under current retail rates. The Bureau of Consumer Protection was very interested in seeing this as the issue was before the legislature at the time.

So the essential conclusion of both the north and south Nevada systems is that they can accommodate large amount of DG when DG is evenly distributed, somewhat less when clustered, but the essential question of when we look at 15 percent penetration most areas of the system can accommodate 15 percent and, in many cases, more DG. And, again, I need to emphasize DG in the form of inverter based technology.

And the third bullet, we also looked at the transmission grid. When we had large penetration of DG coupled with most state renewables we found that there were some transmission impacts. We did network load studies and so they were preliminary but we determined that there could be some impacts with regard to VAR flow, importing of VARs from adjacent system were of real concern to the company.

But the effective conclusion was that the VAR generation system was more impacted by DG at high penetration levels that the power delivery system.

Currently, we’re also working on a follow-up study where we’re examining large scale PV on the order of 100-300 megawatts per installation in the desert to evaluate the combined impact of DG and large PV, especially with regard to looking at the minute-by-minute impacts with regards to reserve requirements, frequency regulation, load following requirements. What are the impacts as we begin to look at highly intermittent PV. The gentleman from SMUD mentioned earlier that 50 percent of loss of PV output can happen on a cloudy day in a one minute timeframe. We're seeing the same type of occurrence. This study is wrapping up now and will be completed by the end of July this year and will be publicly available as well. And indeed we are taking a look at some fairly interesting data. The Sandia National Labs is involved, the Pacific Northwest National Labs is involved as well at taking a look at the operating reserve requirements and impacts. But Sandia has already developed, for our representative year 2007, minute-by-minute profile of 10 large PV sites in southern Nevada. And you can see that on a cloudy day that the variability of low deck can happen. The related question is though given that we're offsetting thermal generation, is there enough remaining generation to be able to follow load and not violate NERC performance criteria under CPS1 and CPS2. And that is the essential question that we're answer and still looking at today. And we'll have an answer in a little more than a month.

And one of the interesting phenomenon, of course is that, you can see that there's numbers on the map of southern Nevada and up in the upper left is number seven. That's a 300 megawatt proposed plant. And so when cloud cover goes across the area, it doesn't necessarily hit every plant at once, so there is some geographic diversity and benefits for large PV. And you can see that in the composite curve on the right.

And that ends my discussion. Glad to answer any question you might have.

CHAIRMAN WEISENMILLER: Thank you for being here.

MR. SHLATZ: Thank you for the opportunity.

MR. THALMAN: Jonathon Thalman from PGE. On your conclusion slide, you had an interesting slide that you omitted to talk about. I was wondering if you could address that for us.

MR. SHLATZ: Certainly.

MR. THALMAN: The reason that I'm interested is that is it just something that we are concerned about and you're talking about the reduction in revenues and how it could be impacted by net energy and net energy metering rules. So it's a concern we have. It's interesting because in your study you show that this was the case. So I'm curious how you found out and how you quantified that.

MR. SHLATZ: Well, the technique that we used, of course, was we conducted productive simulation analyses using ProMod and basically looking at the impact of DG and basically the model of the re-dispatch of the entire system every hour to identify what the change in fuel costs and O&M is, variable O&M, for the system. But then we took a look at the current net metering rules are basically a full offset under current retail rates. Now, one assumption that we made was critically important, and that was about 70 percent of the DG was small. Meaning, it fell under residential rate classes one and two which were all energy rates. Only 30 percent were under commercial rates where the demand charge would be offset. So effectively the rate was 10 cents for example, there was a, virtually, a 9-10 cent credit even under current net metering rules. So the fuel cost offset, 30 percent perhaps of the total plus the additional emission benefits only constituted maybe 35 percent of the total cost of delivery under that embedded or under that retail rate. So the offsetting benefits were predominantly emission and fuel. We found very, very little benefits, in terms of capacity, there were some marginal loss benefits but they were small. Most of these systems were these short feeders, one mile long, and in most cases the loss benefits were less than one percent, except on the very long feeders. There were far more greater number of small feeders. But that's how we came up with the number. And it's hypothetical because 15 percent of penetration, net metering rules at that level just weren't contemplated but it was a stakeholder driven process. One of the stakeholders from the state energy office was pretty adamant that we look at the high penetration levels under current net metering rules.

MS. MARKS: Jaclyn Marks from the, California Public Utilities Commission. I'm very interested to see when this next study comes out and presenting on it. I'm interested in your first conclusion which is that you believe that greater amounts of DG can be accommodated on the existing infrastructure, when evenly distributed, less when clustered. When does less when clustered mean? Can you please clarify that? And the reason that I ask is because we know that the way land availability works and rooftops work is usually when there's clusters and it's not evenly distributed. So how does that really apply in the real world?

MR. SHLATZ: Yes. Well, your state pretty much underscores the impact. We recognize that the system is not ideal and they're not going to get even distribution but that was our starting point. What we mean by less—we were intentionally vague because less meant different things on different parts of the system.

On all of those one mile long feeders in Las Vegas and downtown and the surrounding area, it didn't matter if it was clustered or a one mile feeder or a two mile feeder. You put it all out at the end of the feeder. There's not anything lateral on that feeder. They're all main lines. So it didn't matter at all. That's why we were vague on that point. In a large number of the feeders, clustering didn't matter. On the other hand, there were some were it mattered a lot. Those long feeders up in rural Nevada, out in Elk Grove, where there was more wind generation, plunking down five megawatts of PV and wind at the end of a two megawatt feeder, that type of clustering had a huge effect than if you had evenly distributed over 100 miles. So it really—location, location, location makes the difference in terms of does clustering have an impact.

Frances, yes?

MS. CLEVELAND: I was wondering, given that we've been talking about inverters with the capability to do volt VAR control, do you see if there would be a significant impact if you installed—you know you're not changing the distribution system but if you installed inverters that had pre-specified volt VAR capabilities.

MR. SHLATZ: Absolutely. Yes. We were

looking at the existing system. And a good point that you raised is that we looked at existing technology. We were not asked to look at advanced technologies in terms of having that capability so current rules, current 1547 requirements but everybody on the team understood that, "Gee, if we could vary the reactive output to have it respond to those high voltage conditions, we could mitigate that effect." Yes.

MS. CLEVELAND: I mean, I agree. You have to do what you were asked to do and that's the real world but I was also wondering in your next studies whether it wouldn't make more sense to include that kind of capability?

MR. SHLATZ: Under that study, we're under the same assumptions. In fact, there's even a greater restraint because the study has so many variables we're looking at the snapshot of 2011 only. We're kind of constrained by current technology, current rules but I would say, specially on this bulk grid, where we're looking—the transmission impacts were not capacity transmission impacts of voltage reactive power flows. So your point is so well taken because if there was greater control on that then an ability to manage it would make a huge different. What happened was that as you get greater miles of PV and DG penetration, shutting down some critically loaded power plants which are providing post-contingency reactive support now go away because they’re offline creating a VAR deficit.

Anyone else? Anyone on the line have any questions? Okay. Thank you. Good questions.

MS. KELLY: Thanks, Gene.

CHAIRMAN WEISENMILLER: Thanks again.

MS. KELLY: Chairman, any last comments or any last questions?

CHAIRMAN WEISENMILLER: Again, I’d like to thank everyone for their participation today. It’s been sort of a lively and interesting group. And certainly at this point I think it’s time to move on. I appreciate everyone filing written comments. When are they due, Suzanne?

MS. KOROSEC: July 6.

CHAIRMAN WEISENMILLER: Okay. So thanks again. This meeting is adjourned.

MS. KOROSEC: Thank you. Thank you, everyone.

[Meeting is adjourned at 4:50 p.m.]