UNITED STATES DEPARTMENT OF ENERGY

ELECTRICITY ADVISORY COMMITTEE MEETING

Arlington, Virginia

Wednesday, September 13, 2017

PARTICIPANTS:

NOHA ABDEL-KARIM
North American Electric Reliability Corporation

JOHN ADAMS
Electric Reliability Council of Texas

PATRICIA BARFIELD
U.S. Department of Energy

LANEY BROWN
Concentric Grid Advisors

TANYA BURNS
Arara Blue Energy

CAITLIN CALLAGHAN
U.S. Department of Energy

JAY CASPARY
Southwest Power Pool

CECE COFFEY
ICF

DARIUS DIXON
Politico

JANET GELLICI
National Coal Council

CLARK GELLINGS
Independent

RICH HEIDORN
RTO Insider

JOE HENRY
Deloitte

NATHANIEL HORNER
U.S. Department of Energy

PARTICIPANTS (CONT'D):

PAUL HUDSON
Osprey Energy Group

LAUREN ILLING
BCS, Incorporated

CARL IMHOFF
Pacific Northwest National Laboratory

FERD IRIZARRY
JMH Consulting

KATIE JEREZA
U.S. Department of Energy

MLADEN KEZUNOVIC
Texas A&M University

JOYCE KIM
U.S. Department of Energy

TOM KING
ORNL

ROD KUCKRO
E&E News

ANNA LEIERITZ
Meguire Whitney LLC

JONATHAN MCCULLOUGH
Battelle

DAVID MEYER
U.S. Department of Energy

PHIL MIHLMESTER
ICF

M. GRANGER MORGAN
Carnegie Mellon University

PARTICIPANTS (CONT'D):

JEFF MORRIS
Washington State House of Representatives

ROLF NORDSTROM
Great Plains Institute

BILL PARKS
U.S. Department of Energy

CHELSEA PELLECCHIA
ICF

DAVID PINNEY
National Rural Electric Cooperative Association

BRIAN PLESSER
U.S. Department of Energy

THERESA PUGH
Theresa Pugh Consulting LLC

JAMES REILLY
Reilly Associates

MATT ROSENBAUM
U.S. Department of Energy

BRIAN PLESSER
U.S. Department of Energy

CHRIS SHELTON
AES Energy Storage

PAM SILBERSTEIN
National Rural Electric Cooperative Association

ALISON SILVERSTEIN
North American SynchroPhasor Initiative

RAMTEEN SIOSHANSI
Ohio State University

PARTICIPANTS (CONT'D):

JOSHUA SMITH
ICF

JEFF TAFT
Pacific Northwest National Laboratory

ROB THORMEYER
Utility Tech Council

DAVID WADE
Electric Power Board of Chattanooga

WENDY WALLACE
Deloitte

TOM WEAVER
American Electric Power

CYNDY WILSON
U.S. Department of Energy

YILONG XU
ICF

CHARLES YESSAIAN
JMH Consulting

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P R O C E E D I N G S

(1:00 p.m.)

CHAIRMAN ADAMS: My name is John Adams. I'm normally Chair of the Power Delivery Subcommittee and I'm acting Chair of the Electricity Advisory Committee (EAC) today. Our very first item -- before I even do introductions -- is to get our Ethics Briefing which Brian Plesser, Department of Energy (DOE), is going to provide us. Brian, if I can ask you to take it away, I'd appreciate it.

MR. PLESSER: Thank you. I am Brian Plesser. I recognize a few faces here and some names. I'm from the Office of the General Counsel. I work with Kate Gehringer who you all are probably familiar with because she's asked for your financial disclosure report or has contacted you with various ethics issues.

So, the reason that I'm here today is that as special government employees (SGE) most of the federal ethics laws apply to you as Advisory Committee Members. If you're a representative that's sitting in the ethics laws don't necessarily apply to you, however, you should adhere to them so that there aren't any sort of optics issues that would be raised with your doing any of the things that the SGEs would do. There are obviously a number of ethics rules that apply to federal employees. We're not going to talk about all of those because as Committee Members some will apply to you and some will not apply to you, so we're going to focus on three or four that do apply to you.

In the packet of information that was provided to you I believe that you have Executive Order 12674, and that is the 14 Principles of Ethical Conduct. This is something that President George H.W. Bush made an executive order and is essentially the roadmap for ethical conduct in federal service. It's pretty straightforward. If you have any questions feel free to ask, but you should take the time to read that if you haven't already.

So, my office is involved, we look at

conflicts of interest and that's why we ask for your financial disclosure report. There are two conflicts that we're looking for by and large. We're looking for financial conflicts of interest that you might have and conflict that you might have that arise out of business relationships or relationships you might have with individuals. It's very important that if such conflicts exist you talk to Kate, you talk to Matt, you talk to David and we address those conflicts so that the work that you're doing on the Committee is not questioned, the integrity of the work that you're doing on the Committee we don't want to have questioned.

So, if you have the handout that we're talking about with the ethics law summary, 18 USC 208, which is a criminal statute, provides apps on a specific written waiver or regulatory exemption, a criminal statute bars your participation in your government capacity in any particular matter which would be contracts, grants, if you're talking about reports, in any particular matter if you or any of the following individuals or entities whose interests are imputed to you have a financial interest in the outcome. And those would be your spouse or minor child, a business partner, an organization with which you are employed or affiliated as an officer, director, trustee, or general partner, an organization with which you are negotiating for employment or have an arrangement for future employment.

Now, if you work at an entity like a university where you don't have stock in the entity, you don't own stock in the entity, there's an exception for you to engage in matters of general applicability. So, if there's not a direct and predictable effect on the entity for which you are employed you can continue to work on that matter. Many of you are employed with universities so you will not have this issue. Certainly if the Committee is talking about some sort of report or recommendation that affects a small subset of the academic community and your university and four or five others are the only ones that do that type of research then you need to talk to Matt and David about that before you engage in the conversation.

There are also regulations at 5 CFR 2635.502 which restrict your participation in matters affecting specific identified parties, and those would include relatives or members of your household, individuals or entities with whom you have or seek business or financial relationships with, entities your spouse, parent, or dependent children work for or seek to work for as employees, officers, directors, trustees, consultants, entities that you have served as an employee, officer, director, trustee, consultant within the last 12 months. So, one thing that I know happens in the academic community and with many of our Members on the Advisory Committees is they will consult for an organization, they might have a consulting agreement, you pick up new consultancies all the time. If that's the case you should let Matt and David know about that if it intersects with the work that you're doing here on the Committee. And that would also include if you currently have one and you're not working or you're recused from commenting on that matter there's a one-year period where even after you leave you should not be working on that matter. And then organizations in which you are an active participant such as a Committee Chair or spokesperson.

So, we look at your financial disclosure reports. Kate would have reached out to you and talked to Matt or David about the concerns that she had, and if she did please makes sure you talk to her and not act on Committee matters until it's cleared up.

The next issue that we talk about is misuse of position. Here there is a whole multitude of ways that people can misuse their position. We're going to limit the conversation to do not use or disclose non-public government information. These are open meetings but if you come to learn of some information that's not public you should not be providing that information publicly. Do not use your public office for private gain, either for yourself or another individual.

We've had this problem on, well, certainly in DOE with the federal employees and advisory committees. You need to be careful that you're not doing things that would enhance your colleagues' ability to get grants or contracts from the Department. We actually had an individual who basically provided a recommendation to a Committee that a report was needed and so the person that he was dating actually could benefit from that type of work. And that person got into quite a bit of trouble.

Do not use your official position or Advisory Committee title for purpose other than in connection with your advisory duties. This one I kind of laugh at and the reason is that your home institution titles usually carry much more weight so I would use those rather than Advisory Committee title.

Representations. There are two criminal

statutes, USC 203 and 18 USC 205, which state you must not represent someone else before the government including DOE on any specific party matter in which you have participated as a government employee. And these laws also bar you from accepting fees for such representation done by others. So, if you are in a law firm or in a consulting firm and you have worked on something for the Committee and you have an equity interest in that firm and one of your partners or someone else in the firm is going to work on a matter where you would be included in the fees that would be problematic.

There are also additional restrictions should you work as an SGE for more than 60 days in a 365-day period. If that's the case God bless you and that's absolutely above and beyond. Anyway. And then we also wanted to note that there are additional laws that bar you from serving as an agent of a foreign principle as defined in the Foreign Agents Registration Act which I think up until eight or nine months ago nobody probably had really heard of, but that's an issue as well.

Finally, we like to talk about gifts and the receipt of gifts. The basic rule is that you should not solicit or accept gifts and favors from any prohibitive sources or if the gift is given to you because of your official DOE position. A prohibitive source is an individual organization that essentially seeks to do business with the Department or is doing business with the Department.

There are a number of exceptions. Quite frankly you probably won't be provided a gift in your Committee capacity but some of the exceptions include benefits resulting from your non-DOE business or employment activities or those of your spouse. So, for example, if your spouse is the vice president of General Electric and normally that would be a problem to accept a gift in your official capacity from General Electric you can accompany your spouse to the General Electric holiday party because you're being invited as the plus-one of your spouse who works at General Electric.

You just need to make sure in those instances that the entity offering the gift is not enhancing the gift based on your official capacity. And so if General Electric, for example -- and I apologize if anybody is from General Electric here -- if General Electric were to say to your spouse, "We're having our holiday party and we're putting everybody up at the Four Seasons because we don't want people drinking and then driving home," if you all were put up in the presidential suite, everybody else is in the modest $750.00 a night accommodations you would not be able to accept that. You would have to live like a plebe and stay in the lesser accommodations.

Gifts that are clearly motivated by family relationships or personal friendships, you can accept those gifts. Obviously if the nature of the gift changes based on a friend who is seeking action you need to be attuned to that.

And then items worth $20.00 or less per occasion or up to $50.00 a year from any one source are permissible.

The only time that I've really seen a gift being offered to a Committee was I believe our Fusion Energy Advisory Committee, and I think it was AREVA in France that offered to fly the whole Committee to France to take a look at one of their facilities. So, it doesn't really happen that often. That was a good one, right. We turned that down. But if you have questions make sure you contact Kate. I don't think it comes up that often. And you can certainly hang your hat on these exceptions.

Does anybody have questions that either listening to this or came in with that they want to talk to me about today? If you don't want to talk to me today about them you can always reach out to our office and we're happy to answer those questions. But is there anything that anyone wants to talk about? Okay. I hope that was painless. Thank you very much for your service.

I appreciate you letting us come out and talk to you. I probably won't see you again for a while; Kate might see you in a few months or in a year. So, thanks.

CHAIRMAN ADAMS: Thank you, Brian. I appreciate it. Once again, I'm going to introduce myself, John Adams. I'm Chair of the Power Delivery Subcommittee and today have the honor of adding the role of the EAC Acting Chair to my duties. Basically, for this meeting only I have the honor of calling the meeting to order and welcoming everyone, thanking you for being here.

I know we've faced some hurdles in getting this meeting together. I thank you all for the extra effort of making it here today. Thank you very much. I appreciate it.

I'd also like to thank the National Rural Electric Cooperative Association (NRECA) through Pam for hosting us again. Thank you very much, Pam. Wonderful facilities.

In terms of housekeeping I need to remind everyone you're being recorded so please use the microphones to be sure you can be heard. Please also try not to talk over one another as the court reporter is trying to keep the transcript.

With that, I'd like to go around the table and allow an introduction. I see Pam is trying to finish her lunch so Clark, can you begin?

MR. GELLINGS: I'm not a substitute for Pam but you made a better choice if it made her first. (Laughter) I'm Clark Gellings, I'm what's referred to as an independent. Most of my career I think many of you know is 35 years or so with the Electric Power Research Institute.

MR. KEZUNOVIC: Mladen Kezunovic, I am with Texas A&M University. I've been there for

years for whatever it's worth. Prior to that I worked for the manufacturing industry for about

years or so. I'm happy to be on this Committee, I'm a new Member.

MR. CASPARY: Good afternoon. I'm Jay

Caspary, and I'm a director of the engineering group at Southwest Power Pool in Little Rock, we're the grid operator in the central plains.

MR. WADE: Good afternoon. I'm David Wade, I'm President and CEO of EPB of Chattanooga. We're a municipal electric and communications provider.

MR. MORRIS: Representative Jeff Morris from Washington State.

MR. ROSENBAUM: Hi, I'm Matt Rosenbaum from Department of Energy. I'm the designated federal official for the EAC.

MR. MEYER: David Meyer, I'm in the Office of Electricity at DOE, and I'm a special advisor.

MS. JEREZA: I'm Katie Jereza, the Deputy Assistant Secretary for Transmission Permitting and Technical Assistance. I'm also in somewhat of an acting role because generally the acting assistant secretary, Pat Hoffman, I'm subbing for her today.

CHAIRMAN ADAMS: I'm John Adams, I'm a

principal engineer at the Electric Reliability Council of Texas (ERCOT).

MR. SIOSHANSI: Ramteen Sioshansi, I'm a faculty member at Ohio State University.

MS. BROWN: I'm Laney Brown, Vice President at Concentric Energy Advisors.

MR. MORGAN: I'm Granger Morgan, I have appointments in the Department of Engineering and Public Policy and in Electric and Computer Engineering at Carnegie Mellon, and I codirect two large centers, one in the climate area and one in the electricity area.

MR. NORDSTROM: Good afternoon, everybody. My name is Rolf Nordstrom, I'm the President and CEO of a 501C3 non-profit corporation based in Minneapolis called the Great Plains Institute. We work on energy policy and technology. Nice to see you all.

MR. HUDSON: Afternoon, all. I'm Paul Hudson, I run a little ERCOT focus consultancy in Austin and have some history with the Committee and pleased to be back.

MR. SHELTON: I'm Chris Shelton, I'm Chief Technology Officer at AES Corporation.

MS. SILBERSTEIN: I'm Pam Silberstein, Senior Director for Power Supply at NRECA. Welcome to everyone.

CHAIRMAN ADAMS: Thank you, everyone. I appreciate it. Just by looking around there have been quite a few developments since the last meeting and I'm going to ask DOE to help address that and any other DOE updates. Katie, are you going to take this?

MS. JEREZA: Thank you, John. Very much appreciate that you stepped into this role today. Given current events I really want to thank everyone for joining us here today because it really is a testament to the significance of this Committee and the important work it conducts.

I'd also like to give a special welcome to our new Members. Some of you identified yourselves, but I'll just point out that Mladen Kezunovic, David Wade, Paul Hudson, and Tom Weaver are here today and Michael Heyeck and Brian Olnick could not be here, but welcome to you. I look forward to working with our new Chair, Michael Heyeck, during the current term continuing to address the issues facing our nation's electric infrastructure.

I'm also somewhat new to this Committee as well. I was here at the last meeting but for those of you who are new my background is I was the Director of Infrastructure Resilience at the Edison Electric Institute before coming here. I also spent many years supporting the Department of Energy in research and development, so I had a very broad experience with them before going to EEI. I'm a chemical engineer with an MBA so I love to dive into the technical details but I also like to think that I can do a decent job of trying to explain them as well. So, just a little bit about me.

Certainly the most visible issue the Department is engaged in at the moment is the response to Hurricanes Harvey and Irma. Perhaps some of you had to deal with some flight changes on the way here. As Harvey approached (inaudible) stood up the Emergency Response Organization, also known as ERO, at headquarters and deployed DOE emergency responders to the Federal Emergency Management Agency, FEMA, the National Response Coordination Center in Washington, D.C., and the Regional Response Coordination Center in Denton, Texas, as well as the Texas State Emergency Operations Center in Austin, Texas. ERO was active in monitoring the situation and facilitating coordination and communications with state, federal, local industry partners using EAGLE-I to help track the storm and the impact to energy infrastructure.

The ERO is shifting from Harvey restoration to Irma response. DOE emergency responders have been positioned with FEMA incident management assistant team in Puerto Rico, St. Thomas, and St. Croix, as well as to both the FEMA Region 2 and 4 coordination centers. ERO was monitoring the situation and facilitating coordination and communications with state, federal, local industry partners.

So, when fuel shortages started occurring or were reported as a concern we worked with EPA to issue waivers that allowed more fuel to go into the supply pipeline and examined in concert with other federal agencies additional actions to mitigate potential fuel shortages, authorized release of millions of barrels of crude from the strategic petroleum reserve, and worked with FEMA to have information about fuel shortages posted to its rumor-control page.

For both events we have conducted daily calls with electricity, oil, and natural gas industry partners to identify gaps in resources and to coordinate response efforts. We continue to post daily situation reports, sharing them widely. There has been a real unity of effort by all involved - federal, state, and local governments, our utility and industry partners, and many other stakeholders as well. The response has been very comprehensive and coordinated and DOE is committed to working with all as we begin the restoration for Harvey and Irma. Together we will continue to build an even more resilient, reliable, and secure grid against the storms of tomorrow.

I wanted to talk about some recent awards that the Department has made. So, one of the ways we are working toward a more resilient grid is through DOE's Grid Modernization Initiative, GMI. This past Tuesday the Energy Department announced funding awards of up to $50 million to DOE's national laboratories to support early stage research and development of next generation tools and technologies to further improve the resilience of the nation's critical energy infrastructure, including the electric grid and oil and natural gas infrastructure. Seven resilient distributions systems projects awarded through DOE's Grid Modernization Laboratory Consortium (GMLC) will develop and validate innovative approaches to enhance the resilience of distribution systems including microgrids with high penetration of clean distributed energy resources, DER, and emerging grid technologies at regional scale.

The project results are expected to deliver credible information on technical and economic viability of the solutions. The projects will also demonstrate viability to key stakeholders who are ultimately responsible for approving and investing in grid modernization activities.

The Department is also announcing 20 cybersecurity projects that will enhance the reliability and resilience of the nation's electric grid and oil and natural gas infrastructure through innovative, scalable, and cost-effective research and development of cybersecurity solutions. These technologies are expected to have broad applicability to the U.S. energy delivery sector by meeting the needs of the energy sector in a cost-effective manner with a clear path for acceptance by asset owners and operators.

In the area of advanced grid R&D, lastly, let me take a moment to talk about a project geared not only towards resiliency but economic development as well. Recently the Department announced the Small Business Innovative Research and Small Business Technology Transfer Fiscal Year 2017 Phase I and Phase II awards. The SBIRs and STTRs are congressionally mandated efforts allowing federal agencies with large research and development budgets to aside a small portion of their funding for small businesses. Companies that receive awards in these R&D programs keep the rights to any technology developed and are encouraged to commercialize the technology.

Among the awards were four small businesses, Brains4Drones in Plano, Texas, Elintrix in Escondido, California, Oceanit Laboratories in Honolulu, Hawaii, and RNET Technologies in Dayton, Ohio. These will develop solutions for rapid damage assessment and information sharing for power restoration. Their work will promote power grid resilience by providing utilities with additional tools that can help them recover more quickly from power outages.

As we all know, one of the many challenges that electric utilities face during and after a catastrophic event such as a hurricane or an earthquake is dealing with a lack of immediate access to their infrastructure to perform damage assessments. Deployment of repair crews, movement of heavy equipment, and other response and recovery decisions depend on these assessments.

Floods, damaged roads, and other unsafe conditions that deny access or put workers at risk, however, can hinder this critical step. Delays in inaccuracy and damage assessment can negatively impact situational awareness, decision-making and ultimately power restoration times.

Brains4Drones, Elintrix, Oceanit Laboratories, and RNET Technologies will develop solutions that can improve the timeliness and accuracy of damage assessments including improved information-sharing and enhances situational awareness. Some of the innovative options that these companies will be exploring are smart aerial technologies, advanced sensing, datamining, and satellite imaging, all of which could be used during events such as those we currently face with Harvey and Irma.

Again, thank you all for attending this iteration of the EAC meeting. I know this comes at a very trying time for many of us, however the year-round work of this Committee prepares us to confront challenging events such as these together in an informed and unified way. Thank you.

CHAIRMAN ADAMS: Thank you, Katie. I do have one question I want to hit you with. You mentioned we had a new Chairman, so can you just go over how the leadership is selected for the EAC and explain that process to our new Members?

MS. JEREZA: Sure, happy to. So, the Committee has the Chair as a leadership position and the Vice Chair, and then we have the Chairs of the Subcommittees, Smart Grid, Storage and Power Delivery. So, first what DOE leadership does is they consider who could be a possible candidate for this and try to identify someone they can propose to the Chair of the Advisory Committee and the other leadership as it stands.

If they agree with that proposed person then they talk to the individual and see if they will agree to take on the additional responsibilities of leading that Committee or the Subcommittee. And if all goes well and they agree then they will take over that position.

CHAIRMAN ADAMS: Thank you very much. That's a good lead-in to we have sign-up sheets for Subcommittees outside on the table. In Power Delivery I'm desperately trying to get more Membership into my Committees. Let me put in a little plug: Power Delivery. Or (inaudible)

Storage. I know he's anxious. Smart Grid, Laney. Actually, in this Committee most of the work is done really in the Subcommittees and is brought back to the floor Committee to vote. We are nominated because we are active and are expected to be active in the Subcommittees. We really need your help. So, just my little plug for signing up and participating actively in Subcommittees. Without your participation this Committee can accomplish nothing. So, thank you very much.

Before we move on I wanted to just give a preview of what we're going to be doing over the next few days. Following my remarks we're going to have a presentation by Granger Morgan -- I'm thinking you're done, Katie -- and that will be followed by a panel discussion on modern grid network measurement and monitoring which is organized by our former Storage Subcommittee Chairman Merwin Brown. Merwin rolled off but he was anxious to give us an opportunity to see where the technology is on this, and I thank Merwin for the effort he put into organizing that panel we're going to see.

Tomorrow we're going to start the day with a panel on cybersecurity. It was organized by our former Chair of the Smart Grid Subcommittee, Paul Centolella -- I always have trouble pronouncing his name. I want to thank Paul for his leadership. He has led as the Chairman of this Committee, he's led as the Vice Chair, he's led as the Chair of the Smart Grid Subcommittee and we're going to really miss him. Thankfully, Laney has agreed to step in to present that panel and I really want to thank Laney for that. Thank you for stepping up.

That will be followed by two DOE presentations. Hank Kenchington will talk about the draft multiyear plan for Energy Sector Cybersecurity, and then Travis Fisher will talk about the DOE Grid Study. It was called the 60-day study for a while except it took a while longer than 60 days so now it's the Grid Study. Then we'll follow with Subcommittee reports and finally get to our public comment period.

For the public comment period anyone from the public who wishes to make brief remarks will need to sign up at the registration desk anytime between now and about five minutes before we get to the public comment period tomorrow. So, you've got lots of time if you want to make comments.

We're running ahead of time. I'm tempted to just talk on but I better not. Let me ask, Granger, are you prepared to start early?

MR. MORGAN: Sure.

CHAIRMAN ADAMS: Let me introduce Granger Morgan, the NAS Grid Resiliency Committee Chair and EAC Member to give a presentation on the National Academy of Science's Grid Resiliency Report. Thank you, Granger.

MR. MORGAN: I'm going to give an overview talk and it's probably not going to take an hour. Actually, it will be probably less than an hour. There's the URL for the report and I'll leave it up here just long enough for you to write it down so that you can download it. I am not going to talk about a bunch of the specific recommendations, I'll talk in some general terms about the recommendations, and then if anybody wants to discuss specific recommendations we can do that after I'm done. Everybody got a note? Clark is still writing so we'll wait another minute.

So, this was a study requested by the Congress and funded through the Department of Energy to look at technologies, policies, and organizational strategies to increase the resilience and the reliability of the U.S. electricity system. The Committee Members were expert volunteers in the standard sort of National Academy way. The study took 18 months and we gathered a variety of outside information, we had a lot of folks come in and talk to us, and as I said, you can download the whole report.

The printed version will be out in a few weeks but I have a draft printed version if anybody wants to look at it. We had a very good Committee including a couple of current and former

Members of this Committee, Anjan, for example and Sue Tierney were both Members. And as you can see quite a wide representation. Mark McGranahan from the Electric Power Research Institute (EPRI) who runs their wires part, we had Craig Miller from just upstairs in NRECA, and Bill Sanders both of whom were on the cyber side, and then Jeff Dagle from PNNL and several others who are more on the physical side including Terry Boston who, of course, was also a Member at one stage I guess of this Committee and who is the former President of PJM.

So, most disruptions are brief and local. They come from things like squirrels or birds, lightning strikes, people driving into poles and those are not the subject of this report. Our concern is with wide area outages of long duration. Now, some of those sorts of things could continue a bit to wide-area outages of long duration but most of the outages that most of us experience are caused by these sorts of things.

It turns out that large outages are

rather more common that one might think. So, here's a log-log plot of large events, and you can see this distribution has a fat tail and we've identified a few of the things out there in that tail. In each case I've put at the bottom of the slides -- and I believe that the DOE will put the entire slide deck up, but I've brought a few copies of some subset of the slides if you want to reference them. So, at the bottom of each page is a reference to where it gets talked about in the report.

It's important to point out that resilience is different than reliability. The Random House Dictionary defines resilience as the power or the ability to return to the original form position and so on after being bent, compressed, or stretched; the ability to recover from illness, depression, adversity or the like; to spring back; to rebound.

So, while it's really important to do everything we reasonably can to avoid outages this report is written with the sort of acknowledgement that you do everything you can but you're still going to get large outages from time to time. So, what do you do to get ready for them? How do you minimize their impacts when they're occurring? How do you put things back together as quickly as you can? And how do you learn in the process so that the next time around you do better?

We have organized the report around this diagram. Now, this framing was originally laid out in an article in the Journal of Foreign Affairs by Flynn, and then in an earlier version of this diagram appeared in a report from the National Infrastructure Advisory Council. We modified it for our purposes and we've organized our report around it.

So, we have a chapter that sort of provides introduction and motivation, and then we have a long chapter on today's grid and how it's evolving and what it might look like in the future. But then Chapters 3 through 6 are basically organized around this framework, the kinds of things that could cause outages. And this is an all-hazards approach. We're not focused on any particular one hazard but trying to understand broadly the sorts of things you would do to make the grid more resilient in the face of any wide variety of things that could cause disruption. And then Chapter 4 talks about strategies for preparing and mitigating large area long duration blackouts, things you do before the event. Chapter 5 may be a little unusual in that it worries about what kinds of things you can do to keep critical social services operating to minimize the adverse impacts on individuals, companies, and society during such large outages. And then Chapter 6 talks about restoring and putting things back together and then learning from it. Chapter 7, which is not shown here, basically pulls all of the recommendations out including a set of very large or overarching recommendations that I'll talk about when we get to the end.

I don't need to say much about introduction and motivation. Everyone in the room probably knows this stuff. We stress the fact that electricity is critical to modern society and that if increasingly you turn off the power for any significant period of time lots of things across society have difficulties. For at least the next several decades most people will continue to depend on the functioning of a large- scale, interconnected, tightly organized, and hierarchically structured electric grid.

Now, we talked quite a lot about distributed resources and all those sorts of things, but the Committee's assessment is that for at least the next several decades most of us are going to depend in one way or another, either directly or through backup, on there being a conventional grid. And then while we should do all we can to minimize the possibility large outages of long duration have occurred and will continue to occur so we need to work on that.

Chapter 2 is an overview of the current system. I'm going to skip this because you all know pretty much everything in there. Much of the writing for this chapter was done by Sue Tierney who did a really lovely job of pulling the pieces all together. I do want to stop and talk a little bit about metrics for reliability and resilience and then I will say one slide's worth of sort of looking forward in terms of the future of the grid.

So, for reliability metrics are fairly straightforward. You look back at outages and you do statistics. And I've listed here on the bottom a bunch of the standard things that everybody around this table knows about. And you can then compare how we do with others. For example, we don't look quite as good as some parts of Europe but on the other hand we're spread out much more than much of Europe. So, we can do routine counting of past events and come up with statistics that describe reliability.

That's not true for resilience. Developing resilient metrics for resilience is extremely challenging because that involves assessing how well we are prepared for and could deal with very rare events some of which have never even happened. For example, we haven't had a Carrington-type solar mass ejection since we've had continental scale electricity systems. So, we can do modeling, we can try to assess how we would do.

So, the report recommends that DOE work on improved studies to assess the value to customers of full and partial service during long outages. One of the obvious inputs to trying to figure out how to get prepared is to get some sense of how much consumer surplus there is. For example, getting 150 amp service for a while when I can't have my 150 amp service, what that would be worth. And it also calls for a coordinated assessment of the numerous resilience metrics being proposed. To speak now, personally, I'm not persuaded that any of them are all that useful yet. This basically requires modeling and assessment of things that haven't happened yet. One could improve in that space but we haven't done as much as we should.

The final part of Chapter 2 walks through a bunch of things that -- we do not spell out a scenario or two or three scenarios of the future grid, we instead say, well, there are various ways in which distributed versus centralized issues could evolve both in terms of regulation and in terms of technology. There are various ways that those distributed resources could actually take shape. There are various regulatory environments that could develop that encourage or discourage some of the future possibilities. There are various ways that the bulk system could evolve. And then both climate change and extreme weather obviously both effect and can be effected by how the power system evolves.

So, again, if you're interested you can go to the back of Chapter 2 and take a look at all these, but we quite intentionally did not spell out one or a couple of scenarios of our best guess of how the future is going to evolve because our sense was that it's anybody's guess and it was much better to sort of lay out the range of things that could happen.

We wrap up Chapter 2 with five summary observations and I already mentioned a couple of these. Obviously the grid is undergoing dramatic change, but much of the hardware that makes up the grid is very long-lived so a lot of that stuff is going to be there for many years. No single entity is in charge of planning the evolution of the grid, and a corollary to that that I'll come back to and talk about more is that nobody is in charge on resilience. Lots of folks have as a primary responsibility worrying about reliability; almost nobody really has as a primarily responsibility worrying about resilience in the sense that I've defined it here so we'll talk more about that. All players will be concerned about -- well, this is what this next point says -- and then virtually nobody has a primary mission of building and sustaining system-wide resilience.

Now I'm going to walk you through the four main chapters of this report beginning with the many causes of grid failure. This chapter talks about a dozen or so different things that could cause large scale wide duration outages. I've produced a little taxonomy here. Some of them are physically induced; terrorist attacks, a bunch of Washington- style snipers go around and put holes in 507 65 KV transformers. That could cause very large-scale outages for long periods of time. Cyber attacks or operational errors. A number of the large power -- those often don't cause equipment damage so it's not too hard to put things back together, but we've had some large blackouts, of course, that were basically largely the result of operational or operation errors.

And then on the natural side a long list of things here, some of which are -- well, we've had two obvious examples of hurricanes recently, many of us can remember the ice storm from Quebec and upstate New York. I don't want to walk through all of these so I've put together this little collage to just make it a little more salient to everybody, and I'll start in the upper left corner.

That red report -- actually I need to go back and check the date, but over 20 years ago the old Office of Technology Assessment put out a study that basically said that the grid is physically very vulnerable. And in contrast to the second report there that I chaired on terrorism and the electric power delivery system where we were really careful not to say what I said in this room a moment ago, namely if you want to bring down the power system find a bunch of guys who are reasonably good marksmen, order high-powered rifles and armor-piercing bullets on the internet and send them out to go after high voltage transformers. We didn't say that, but that earlier OTA report does say that. I presume that in this room I'm not giving ideas to anybody.

The lower left picture is to remind us that earthquakes can really do a job on power systems. The operating room here is just to remind us also that operator error can be an issue. We've all seen these pictures of the tows from Hydro Quebec bringing power done from Laurent and that, of course, put a lot of people in the dark in the middle of very cold winter weather, often in some cases for periods of weeks. Your pipes start freezing and all kinds of pretty bad things happen. We know about hurricanes.

The picture in the lower right is interesting. We don't think of tornadoes as causing the kinds of -- you know, a tornado can cause a local or short-term outage, but that's a NOAA picture of a whole chain of tornadoes which happened to move right up through some very critical power system assets. So, as the intensity of tornadoes perhaps changes over time -- and there is careful discussion in this chapter. We had NOAA in to brief us and we were really careful to try to say what we thought we could and could not say in terms of how climate change is likely to affect various extreme events. Climate change clearly is already causing much higher sea surface temperatures and so causing stronger Atlantic hurricanes, it's causing more intense rainfall. But on tornadoes the science is out. You can't say yet what the impact will be.

The two in the upper right corner here, the purple and the white are reports, are just reminders that solar mass ejections are also potentially a fairly major cause, especially at northern latitudes with particular ground conductivities. We include a diagram like this that says how much warning might we have and how long might it take to put things back together.

The E there is for earthquakes, and you'll notice there's this horizontal bar that goes out. That's because today, of course, in some parts of the world we have instrumented faults. So, for example, Mexico City gets advanced warning of an earthquake out in the Pacific because it's instrumented and they get telemetry and the speed of light is a good deal faster than the speed of earthquake waves. Similarly, the Shinkansen gets shut down if an earthquake is detected before it actually often gets to where it is on the tracks and so on.

Anyway, you can download that chapter and take a look.

Let me now talk a bit about Chapter 4 on strategies to prepare for and mitigate large area long duration blackouts. Again, download the thing, look at it. All through this report there are specific findings and recommendations. Many of the recommendations are targeted to particular organizations. In the back, in Chapter 7, we pull all those out and we organize them by who they're directed to. So, there must be 15 or 20 that are directed to DOE and there are some that are directed to DOE together with the Department of Homeland Security (DHS) and maybe also with EPRI and some utilities. So, we can go through those if you want but I'm not going to go through the detailed recommendations so much as to trust give an overview.

So, Chapter 4 talks about technical opportunities for enhancing system resilience. You can read faster than I can talk, so you can skim down that. Each one of these is a header and in the report you'll find fairly extensive discussions of each. I might mention just one or two. So, there's intelligent load shedding and adaptive islanding. Under that one of the interesting ideas that we talked a fair amount about is the notion that maybe you could power down some critical facilities when you know there's a problem coming. I mean, if you get a

second warning that there's going to be an earthquake you might try to power down a few things rather than leaving them energized because then they might ride through better. That's not something that's routinely done or where there are standard protocols to decide when to do or not do that. So, that's an example of the sorts of things we're talking about.

Enhanced modeling and simulation, there's quite a lot of talk. And there's talk about also getting better more realistic data sets to work with to do some of that. And then at the bottom cyber resiliency here's a whole slide on cyber resiliency.

I'm not going to walk through all of this, you can download it and look at them. But I do want to stress one thing and that is that we're using the word resilience as opposed to security here intentionally. Cybersecurity basically implies trying to keep the bad guys out. I mean, it's security in the sense of the physical side as well. But the evidence is increasingly compelling that the bad guys in many cases are already in, they may be just sitting there just waiting to turn something on. So, my colleagues wouldn't let me use this phrase but partly I'm thinking in terms of cyber black start, that is suppose I managed to really screw up the system, how do I put it back together, how do I run it in minimal ways, how do I operate in a reduced capability when I'm already infected?

Now, in the defense community of course these sorts of things have been worked on for a long time with respect to networks systems, and in the power system area there's a fair amount of discussion. But the key point I'm making is that cyber resilience is a broader kind of issue, keeping the bad guys out just as keeping the power always on is virtually impossible. So, it's time to start thinking about what do you do when you can't keep them out but you have to keep providing some minimal service.

So, here are recommendations from Chapter 4. The first couple are pretty obvious. There's talk in there about improving modeling and strategies to mitigate the impacts of severe events. The power guys on the Committee thought that there's still an urgent need for some better synthetic data on large scale. Well, you can read this list probably faster than I can read it so I'll just let you glance for a minute before I move on. Awareness and information sharing between dependent infrastructures, the connections to natural gas of course are really quite serious and probably have not been explored quite enough. Again, on pages 4-8 to 4-38 of this draft version you can find all of this talked about at greater length.

Chapter 5 is so the power goes out, what are the sorts of things you can do to reduce the harmful consequences during an outage? Experience suggests that we've done a bunch of things. Hospitals have got backup generators and they've got fuel contracts and so on. In big outages it's often the case though -- or even in smaller outages for this first point -- it's often the case that when you fire up that generator it doesn't work. Now, yes, everybody knows good practice means that you're supposed to start generator on a regular basis and so on, but we've had blackouts in recent years when hospitals that assured everybody that they had backup didn't have backup when the power went out.

The issue of fuel reliability is also important. You may have what you think is a secure delivery contract but if the problem is widespread enough or if somebody with more clout moves in and commandeers the tankers or something there can be problems there as well.

And we need more work on advanced

preparations for use of non-traditional sources. I've shown a locomotive there. During the Canadian ice storm there was some -- locomotives of course produce DC and so I've got to have a box that can convert DC to 60 hertz AC and if I don't have that box a locomotive is no use. So, thinking ahead and having some of that capability, similarly for ships in harbors. The Navy doesn't like to talk about this, but they have on occasion helped out and there are lots of other ships around. Cruise ships are enormous mobile generators. So, working on some of that.

And steps should be taken to make it possible for those with rooftop PV to obtain power during outages. So, I've got PV on the roof and I've got some battery storage, but at the moment almost certainly my inverter is designed so the minute the grid power drops I no longer have power. Well, you know, there are some regulatory and safety issues that have to be sorted out but we ought to sort them out. It ought to be the case that people across southern California when they have an earthquake that takes down much of the power system, if they've got PV on the roof and some battery can at least get 15 amp service for much of the day. The other one listed here is the use of hybrid and fuel cell vehicles for distributed backup. Increasingly we're going to have little generators sitting in our driveways. Now, there's a problem at the moment which is that if I do that I violate the warranty, and so there are legal and regulatory and other issues that need to be sorted out. And at the moment, of course, I've got no way to do it even if I'm willing to violate my warranty. But those are some of the kinds of things that we argue people ought to be thinking about to reduce the vulnerabilities when one of these large outages occurs.

I mentioned this one before. While there have been a variety of studies done mainly by utilities to meet the demands that PUCs place on them of what people are prepared to pay to avoid outages. Most of these have focused on periods of less than a day. We know very little about what society is willing to pay and the value derived from full or partial backup service.

Actually now to sort of take off my hat as Committee Chair here and just say a word personally, we have a doctoral student right now at Carnegie Mellon who has been working on this problem and she has developed a fairly elaborate interview protocol to elicit people -- she lays out a very detailed description of an outage scenario, she gets people to build their load profile, she gets them to think systematically through all the costs. She sees lots of consumer surplus, that is the first 10, 15 amps is worth a whole lot more per kilowatt hour than getting my full 150 amp service back. And there's technologies around that if we thought it through we could make that possible in many isolated islanded feeders.

So, we talk about those things and we talk more generally down here -- we've all seen diagrams in the lower left there, and 80 percent of it is vapor ware but 20 percent of it is real, and it would be nice to make a little more of that vapor ware real. So, some utilities can do islanding because they've got distributed generation but many have not installed interrupters or other things so that they can sectionalize.

Then we've got regulatory constraints. This picture in the lower right is actually out of Chapter 2, not Chapter 5, but the diagram at the top is a building with, say, a micro turban that's supplying the building. Under federal law utility must connect. Take those five floors, point them down across the countryside, make them separately owned, and put in that small distributed generator. That's illegal in most U.S. states both because you're crossing public thoroughfares and because you are selling power to separate private entities. So, unless you become a licenses utility -- so, there's a discussion of those sorts of issues as well.

The final chapter, before wrapping up,

is the issue of restoring grid function after a major disruption. This is actually Craig Miller whose office is not here at the moment, he's out in Colorado, but this is Craig's picture. It basically says at each level across the system you need to assess provision, prioritize what you're going to do, and then set out and do repairs. And you do that at the regional level, at the system level, for each site. And, of course, one of the things is figuring out what's out there and what's broken.

So, there's discussion in here of things like getting clearer guidance from the Federal Aviation Administration (FAA) on the use of drones. The situation is evolving and FAA of course will generally provide fairly quick permission to fly drones to assess the state of things. But at the moment there's no standing arrangements to make that easily possible. So, you can find in this chapter a fair amount of discussion on each of these stages.

And the chapter again wraps up with a

set of recommendations. I'll only talk about a couple of them. There is the recommendation for stockpiling high voltage transformers. Everybody in the room probably knows the long history of this. DHS did after the terrorism and the grid report run one demonstration, and since then too the utilities themselves have made a lot of progress in terms of developing catalogues of who has got what and that sort of thing but we think a little more is needed in that space.

We also think that it's really important to continue to push the work that the Office of Electricity is doing on advanced large transformer designs. I mean, if I can build transformers with substantial solid state capability so that I can tune them to meet the electric properties of the place I want to drop a transformer in that could make a big difference in rapid recovery. And you can read the rest of these; they're pretty straightforward.

I mentioned at the outset that there's a problem in this space. You can suggest all these smaller things that DOE and utilities and EPRI and NRECA, all these folks can do but collectively even if they do all of that it doesn't fully address what we think is the problem of achieving a high degree of resilience for the U.S. power system. So, we have seven sort of overarching recommendations as well as all these detailed ones that are addressed to particular entities. I've really boiled them down here so if you want to see the details, again, you need to go in.

The first thing is we've tested. We run tabletops and other exercises. We need to continue to do that and we need to do it for larger scale scenarios for both physical and cyberattacks. This is not scenarios for both physical and cyberattacks, this is not something that is new, I mean, we're doing these things. It's simply to say they're important to do and we should do them perhaps more frequently or at a larger scale.

The second thing is there is lots of technology and capability out there that could enhance resilience. So, Florida Power and Light, for example, is telling us that as a result of some of the things they've learned from the previous hurricane they think they're in better shape in putting systems back together this time. One thing that I'm aware of is that in the past the reinforcements in the concrete poles only went about halfway up and then the poles snapped where the rebar ended; now the new poles apparently have rebar all the way up. So there are all kinds of simple or more advanced things that could be done and we need to try to accelerate the process.

The problem, of course, is how do you pay for some of these things? Florida Power and Light probably doesn't have much difficulty getting it's PUC to agree to pay for stronger poles. But some of the other things that we talk about in this report that provide protection against events that may only happen, if ever, on decadal time scales paying for them is a tough problem. And so there is discussion in this report as well about strategies. Some of these things you want to pay by putting them in the rate base, but others because they mainly provide broad social resiliency and meet social services you may not want to use the rate base as the way to pay for them. We don't have conclusions about how to do it but we do raise a number of issues that we think deserve future consideration.

I'll speak just a little out of school here. The rules of the National Academies do not allow us to tell an agency how to spend its money. So, this recommendation does not say the work being done by the Office of Electricity in the Department of Energy is really important and you ought to continue to fund it. What it does say is the work that the Department of Energy is doing in this space is really important and someway or other the DOE ought to continue to fund it and the Committee is very unanimous in its view that that's the case, that that work really does need to keep being funded. How it gets funded, of course, is the DOE's concern but continuing to support it we believe is critically important.

Then there are a couple of sections here about both physical and cyber components that need to be boosted. I'll skip these because we've already talked a bit about it, but these are sort of broader more overarching ones.

Then the last ones here are a little unusual. I said nobody is in charge and I also think very few people think about exactly what the consequences of a very large broad-spread outage would be. Now, you know, we're getting an opportunity to do that in Texas and Florida, one that maybe we didn't want, but hurricanes are not the only thing as I said at the outset. We argue that there needs to be a process to more systematically imagine and asses what happens if the power goes out and it stays out for a long time.

Years ago we did something like this in Pittsburgh with students and it turns out that a lot of stuff across Pittsburgh that's fairly critical, like the pumps that move the sewage up over hills and stuff, all stop working and nobody thought very much about it. We need to be doing more of that sort of stuff at the national level, and then we need small groups that informed by that visioning say, all right, what should we be doing at the federal level, at the regional level, and at the local level? We're not naive; we don't expect that this will result in a sudden transformation of how people think about these issues. But if we can't raise the visibility of the level of vulnerability that our society faces to large scale long duration blackouts then because there doesn't seem to be anybody uniquely in charge of worrying about resiliency I think progress will be much slower than it ought to be.

So, with that I'll stop. And actually I'll just go sit down and you can run the discussion. I did bring not all the slides, but here's a subset of them.

CHAIRMAN ADAMS: I see Laney had some questions and I think I'm going to invite her to ask them. I've certainly got some.

MR. MORGAN: Go ahead, shoot.

MS. BROWN: Thanks. I was actually looking at your slides to make sure I got it right but the slide I'm thinking about is not on here. I think it was one of your first ones. That's your statement that large scale outages are larger than we think. And my other question is around value. Generally speaking metrics like CAIDI, SAIFI, and SAIDI can be or usually exclude major outages.

MR. MORGAN: Yes, right.

MS. BROWN: And I'm wondering if that is an indication of the perception of why large-scale outages are more common than we think. And then also how that might relate to articulation of value or investments from a cost benefit perspective.

MR. MORGAN: So, three thoughts. Yeah, it would be nice to have those metrics with and without large scale outages. I don't know that you want to just start including the large-scale outages, I think you might like to see them both ways. But on the other hand, because they are such rare events -- and some of the kinds of things I've talked about have never happened but we know could happen -- it's not going to be a fully adequate metric. One of the things that one is going to have to do is build better simulation strategies for some of these events. And we've done it for individual hazards but we need to sort of look across all hazards.

Now what was the second half?

MS. BROWN: I'll just say I have some background, some successful (inaudible) in building cost benefit analysis justification of hardening investments.

MR. MORGAN: I teach a course on theory and methods in policy analysis and I just yesterday gave the first lecture on benefit cost analysis and the limitations that it carries. Yes, in some context you can probably actually do quantitative benefit cost analysis, but a lot of the issues here involve social vulnerabilities. I mean, it's easy enough to put dollar values on disrupted business and that sort of thing; it's complicated by the fact that there's rebound so I'm out for several weeks but then I may fill the backlog of orders faster than I might have otherwise cranked them out so that's simply the sales rate times the amount of time is probably not an adequate -- may either over or underestimate.

But addressing the broader issues of social disruption -- I mean, our whole social infrastructure depends on electric power. Yeah, I'm sure there are a handful of economists around who would be perfectly happy to try to quantify all of that stuff. I wouldn't believe the answers.

(Laughter) But I do think that there are some quantitative inputs that you need. I mean, you need to get members of societies, both companies and individuals, to think more about their willingness to pay to avoid these sorts of issues and that's clearly an important consideration in making a judgment of this sort. And you do need people to figure out what could be done.

I mean, in the case of south Florida, for example, where I've flattened large amounts of distribution system if the wires aren't there even an isolated feeder as a microgrid is not going to be all that feasible, and if some of the wires are there I still have to make sure which ones are there and what I could safely bring up. But there are other settings in which if I've got a modern distribution automation, if I have meters that I can actually limit the amperage, that is where I can actually cut back and say, all right, you may have 20 amp service but if you go above that I'm going to knock you off -- I mean, at the moment I either have to run a whole feeder or I don't run a feeder. I can of course with smart meters disconnect individuals but I would like to be able to maybe in long outage cycle individuals or give them lower amperage. I can design all of that stuff technically and I can cost it out, but at some stage then with those sorts of evidence and with willingness to pay evidence then different regions have to say, oh, I'm the Washington, D.C. area, I'm pretty vulnerable, maybe I'm willing to make some fairly large investments. I'm someplace in the Midwest where the risks of terrorists or other attacks is pretty minimal, where I'm not going to have hurricanes, maybe the cutoff point at which I decide to make investments is at a different level.

MS. BROWN: I was just going to say I think from my experience articulation of value at least starts the discussion.

MR. MORGAN: Yes, exactly right. And the other thing is -- I mean, the reason for these -- I'm an engineer and I had a couple of engineers on this panel who it took a while to get comfortable with this notion of a visioning exercise. But I really do think -- and the Committee all came around to this view -- that spending some time just thinking through systematically what could happen and what would it be like if I lose power for an extended period across a wide area. We haven't done enough of that. We're obviously doing that now in hurricane areas but we haven't done it in Los Angeles in the context of earthquakes, we haven't done it in the Pacific Northwest in the context of volcanism and earthquakes, we haven't done it for the upper northeast in the context of solar mass ejections, and so on.

CHAIRMAN ADAMS: Thank you. Rolf?

MR. NORDSTROM: Thank you, Granger, that was great. Rolf Nordstrom with the Great Plains Institute. I have two questions. You might have answered the first one just toward the very end there, but you noted that really nobody in society has the primary mission of building and sustaining the system-wide resilience. Was the Committee's conclusion that it should be a joint responsibility of DOE and Homeland Security or were you just suggesting that those two agencies sort of take this first stab at a visioning exercise? Do you know what I'm asking?

MR. MORGAN: Yeah. We think the visioning stuff is something that can be done naturally. But the DOE and the Department of Homeland Security don't run the U.S. power system so they're not the people who get to make the decisions about hardware choices, investment. They can run demonstrations. And so throughout this report we do talk about the critical role that could be played by choosing one or another technology that could really help in demonstrating it and also showing what it costs so that, for example, when a community, having raised awareness, then decides, gee, maybe we are kind of vulnerable, maybe we ought to make some investments or PUC does that then they can -- I mean, the problem is -- I just talked sort of loosely about turning distribution feeders into islanded systems running with distributed resources and meters that could cut be back from 150 amp to 20 amp service and so on, bits of pieces of that exist but if a PUC or if the city of Pittsburgh or Milwaukee or somebody decides they want to do it, it would be a whole lot more reassuring if you could say, oh, well, and the DOE ran a small demonstration and demonstrated they could do all of that.

Now we do talk in the report about a few examples where utilities with some more advanced capabilities have, for example, managed to reconfigure distribution circuits and dramatically reduce outage extent and duration.

You had a second half --

MR. NORDSTROM: Well, the first one I guess really is does the report make a suggestion about whether or not somebody should have primary responsibility, and if so who? That's really the first question.

MR. MORGAN: Yeah, well, there's the big problem. It isn't apparent who. Chapter 2 goes through a very long description of the current system. Nobody is in charge. And if nobody is in charge of the simpler issues of just upgrading existing hardware and so on -- I mean, the simple answer is no, we don't make such a recommendation because we didn't see any feasible route to do it.

MR. NORDSTROM: And then my second question is -- and I apologize because I couldn't figure out how to ask this without having it sound sort of leading, but I don't intend it to be.

MR. MORGAN: That's fine. I can duck.

MR. NORDSTROM: Given the number of base load plans that are in the queue for retirement in the next 20 or 30 years, so reaching the end of their at least licensed lives, does the report make any sort of recommendation about whether or not utility regulations should require or encourage what I guess I'll call a new design assignment for replacing all that energy and capacity in ways that make the system inherently more resilient? In other words, as we are going to be inevitably faced with replacing old and retiring infrastructure should we just absolutely make sure we don't miss that natural infrastructure turnover opportunity to make sure we're rebuilding the system to be as resilient as we can possibly imagine it to be?

MR. MORGAN: We didn't fully duck.

MR. NORDSTROM: Did I ask that clearly?

MR. MORGAN: Yeah, I understand. But if you go into the end of Chapter 2 and you look at this stuff a lot of this addresses those issues. The simple answer is we -- I mean, there aren't recommendations because that's a rather broader set of issues, but we do try to lay out a range of the things that could either enhance or exacerbate the resilience of the system. And you're absolutely right; if certain kinds of developments occur in the short to medium term they could end up producing a system that is significant and less resilient.

MR. NORDSTROM: Thanks.

CHAIRMAN ADAMS: There are a couple people ahead of you. Go ahead. Put your card up and I'll --

MR. MORGAN: And then turn your mic on.

(Laughter)

MR. KEZUNOVIC: I was going to make a

few comments so it's really not questions, but since you've been involved in the work of the Committee you may respond and some others may too.

The first comment is that in terms of this Committee, this Committee has Subcommittees and listening to you I guess you would probably agree that the topic of resiliency wouldn't reside necessarily in any single Committee.

MR. MORGAN: You're making precisely the point that he did, namely it's across all our Subcommittees, it's across all operators and players in the grid.

MR. KEZUNOVIC: Right. I'm glad you hear that. Secondly, which is more related to -- I shouldn't say definition of resiliency necessarily but the scope of resiliency that the report was addressing. There are statistics that are out there that say that we have catastrophic events -- I will call them catastrophic like the hurricanes and stuff like that, and they obviously impact the economy and everything else -- but in terms of outages the percent of time that electricity is not available due to those events is about 7 to 9 percent and the remaining is everyday outages, if you want to call them which leads us to think about resiliency in terms of the scope that goes across the entire timescale of operation of the power system. Regularly you can have faults, they may cause outages, those outages are counting towards the electricity being disrupted. So, I think that the scope should probably be broadened.

The moment we broaden the scope then we are going into things that are everyday things that we do with power grid, maintenance, for example, maintenance practices and so on. Because when you think about the overhead part of the system you have deterioration of assets meeting a hazard of weather, for example; not catastrophic weather, sever weather, just storms, lightening, stuff like that. And between those two things faults occur so improvement in maintenance, for example, is a big part of it. The moment the fault occurs the protective relaying starts acting so it can misoperate. So there is now this issue of protection selectivity, dependability, and so on, characteristics of the protection.

And by the way, the maintenance practices and protection practices have been around forever. So, the question that this whole discussion begs is do we need to go back to basically fundamental practices, how we're running everyday business, not just the business at the time where we have the catastrophic events. So, that's kind of a scope comment on resiliency.

The third and last is about the responsibility or however you want to call it to whoever should take action. I agree with you, utilities are running systems so if it's anything related to that utilities are the first in line. However, what would be interesting to know -- and this report has brought up all of that, but just to kind of pursue further the discussion -- is to precisely associate the resiliency issues with either practices or equipment or technology or something of that nature because that leads directly to a responsibility.

So, if I am running a utility company and the practices for maintenance need to change then that's in my purview. If I have technology in relaying that has sort of limitations and because of that there may be misoperations and cascading events then the technology world has to step in.

Totally separate is the issue of who pays for what because that's kind of a -- however we should agree in a society who should pay for what at the end.

So, I will finish by saying that if we are to undertake in this Committee further actions related to this report I would absolutely recommend that we think how to do it in terms of the structure of the Committee and try to further discuss the scope and, hence, to discuss somehow at least the targets where the expectations are that something if done about those targets would improve the situation.

So, I don't know what you think about

this but I just wanted everybody to kind of open their mind.

MR. MORGAN: I'm going to simply say thank you and take that as a comment that the Committee as a whole can consider.

CHAIRMAN ADAMS: I think I'm next. I've got several but I'm just going to ask two I think.

The first one is in what I think was slide 3, I think it was a log-log plot, I'm not sure. It might have been a semi-log plot.

MR. MORGAN: No, it was log-log.

CHAIRMAN ADAMS: Was it log-log? There was a curve that you didn't talk about at all which I think was a theoretical curve. What I'm wondering is, hey, is that what we're planning on? The curve (inaudible) a lot less events?

MR. MORGAN: That's a simple Gaussian or Weibull so, yeah. If you fit -- well, I don't have a cursor. Maybe I have a pointer.

CHAIRMAN ADAMS: On that graph the outer one was the actual events fitted on log-log but then there was another curve and I'm wondering if that curve is what we're doing --

MR. MORGAN: How do you turn this thing back on?

CHAIRMAN ADAMS: I think the answer is yes but I'm --

MR. MORGAN: I can answer the question, we can't see the curve. (Laughter) What the dashed curve was is fitting of Weibull to the more common events and then extrapolating it out to the largest ones. When you do that extrapolation it turns out you get a fatter tail than that. So, it's only in that sense that that curve is saying that large events are more common than one might think if one simply extrapolated from the more common squirrels and people driving into poles and stuff.

CHAIRMAN ADAMS: And I'm going to display my ignorance. I guess I'm still thinking that when we do our loss load probability calculations we're probably using that inner curve. Is that what you were thinking?

MR. MORGAN: Yeah, well, and you're

probably not going out very far either. I mean, you're probably not worrying about the Canadian ice storm or the south Florida hurricane. I mean, in those cases, as Florida Power and Light has, you do all sorts of preparatory stuff.

CHAIRMAN ADAMS: I'm going to jump to a simpler one, and this is an opinion I'm asking for. What should the EAC do with this? Do you have any opinions on what actions we should be taking? Advice?

MR. MORGAN: Well, look at Chapter 7 at the back part where by category we go through a bunch of recommendations specifically to the DOE and see if any of those -- I think a few of those do probably raise issues that it would be appropriate for this Committee to think about. I have not thought systematically about that. But look at the back half of Chapter 7 where we have organized recommendations by who they're directed to and I think you will find -- I don't know what page, it's probably about 7-8 or 7-10. Yeah, it starts on 7-7.

So, the reason they're organized this way is partly that the review process at the Academy tried to make us boil these down to just a handful and we thought it was important to be specific. So, there are high level ones beginning on 7- 7. For example, 7-7 is in proof understanding of customer and social values, and so then there are a couple of specific recommendations under that. And on top of Page 7-8 support research development and demonstration as well as blah, blah, blah. And then there are four specific ones under that and so on.

So, I would read those four or five pages. For example, you might just copy those pages and send them out to all the committees and say, you know, do you see anything in here that it might make sense for us to be thinking about.

MR. GELLINGS: It's copyrighted. Don't do that, it's copyrighted.

MR. MORGAN: Don't do that.

CHAIRMAN ADAMS: Jeff, I think you're next, then Laney again, then Clark.

MR. MORRIS: I have one short comment and two questions. The short comment is based on the institutional memory. I always get a little bit sad when I think back to the 2003 Blue Cascade exercise that the Department of Energy funded and one of the top recommendations was credentialing line workers to go out and enhance recover and I saw that on your list. It's 14 years later and nothing has been done on that topic.

MR. MORGAN: You know, when Jeff Dagle had been involved in a bunch of these retrospective things as well and was actually very helpful in developing some --

MR. MORRIS: And for border states that's where reciprocity agreements goes across the border for line workers, that's a real key issue for all those jurisdictions.

My two questions. At the state and province level kind of the gold standard is what Alberta has done where they brought a lot of their generals back from the Bosnian conflict and they did a complete province-wide military assessment on cascading failures for taking out critical infrastructure nodes, particularly the grid.

MR. MORGAN: From terrorist interventions.

MR. MORRIS: Well, they just took a military view like they're coming in with jet planes, they're going to start blowing stuff up. It didn't really matter how it got blown up. But they parked right next door to that -- 1,000 nodes in the province right next to the recover shop on the same floor. I'm wondering if one of the recommendations was used in that type of military targeting assessment and trying to figure out the cascading failure impact not only with the grid but for other critical infrastructures as well.

And then my second question is that when I talk to all of our chief information officers or IT people at the state level or for public power the first thing they tell me is that, hey, whenever you're talking to the federal government please share with them that what we need help with is to bifurcate the traffic we're seeing hitting our system because we don't know what's a fifth grade class exercise in China or organized crime coming in from the Eastern Bloc when it's hitting our system from the outside. Any help in bifurcating that traffic would let us focus on what's really a threat versus some items that are not.

So, I was surprised I didn't see that in what you presented, but maybe it's buried actually in the paper itself and not in the topline that you presented to us.

MR. MORGAN: Well, on the first one there is a lot of discussion across the report of better modeling capability and more realistic data sets which are sort of the precursor to working the problem you just described. I don't recall that there is specific language to the problem you described, but I think that if you did the sorts of things that we're recommending you would be in a much better position to do the sort of simulation studies that you just talked about.

On the second one, again, it's pretty

generic. That is, all across this study we have tried to be sort of all- hazards but I don't think there's any discussion on differentiating the nature of the hackers essentially that one is dealing with. If you're interested the person to talk to is Bill Sanders, who is head of Electrical Engineering at Illinois and who is sort of the principle guy who has worked on the ideas of cyber-resilience in this report. Craig Miller upstairs here also has worked in that space as well. But I'd start by sending a note to Bill Sanders. He's head of Electrical Engineering at Illinois so you can do an easy web search.

CHAIRMAN ADAMS: Laney, I have you up again.

MS. BROWN: Just quickly, one of the recommendations was to look at best practice from a technology infrastructure. I think actually there may be a lot of looking at best practice. Is that best practice easily obtainable or is there a need for collection centralization, et cetera, for best practice? And I know it can be broadly.

MR. MORGAN: Well, some of it is and some of it isn't, and that's in fact why we're recommending some demonstration activities. But if I'm interested in using intelligent sectionalizers and that sort of thing in a distribution system there are plenty of utilities around that are doing that already and where you can call up their chief engineer and get told how they've done it, what it cost, and what it does and doesn't achieve.

CHAIRMAN ADAMS: Clark, I believe you're next.

MR. GELLINGS: A couple of quick comments. First, my thing about don't send out copyright pages was strictly thinking about too many years as a research manager. Once something is copyrighted or about to be copyrighted don't send it out to somebody else without all the right permissions and so on. You know that, right? But what you can do is you can make a note out of it, a subtext if you will, and ask for comment about it.

MR. MORGAN: I can easily get you permission to reproduce this and send it around.

MR. GELLINGS: There you go, okay. My broader comment was really on the way we've been tossing some of these words around. Loss of load probability is not equal to willingness to pay. Let me tell you as a former commissioner in New York post-Sandy to try to reconcile what might be done in the area of impact prevention, recovery, and the like. First of all, the willingness to pay changes dramatically once they've experienced something like Sandy, or we could turn to the U.S. and these other events that have just happened in the last week or two. So, willingness to pay is not loss of load probability nor is it cost of putting the resilience in place that would be necessary. The enthusiasm in the northeast for independent systems and the like or the integration at some level or central and distributed resources is much different than it is in other parts of the country right now.

The other thing, it didn't directly come up but this haphazard way by which we so glibly say, oh, let's put it all underground. What we learned in New York in fact is --

MR. MORGAN: It floods.

MR. GELLINGS: Well, you know, electricity and water just don't happen to mix very well. So, that doesn't solve your problem necessarily. It does give you a different cost profile which no matter what we've done we still don't see much less than an eight to ten times expenditure difference between the overhead and underground systems.

MR. MORGAN: Clark, you will not find anywhere in this report that says outage probability is correlated with willingness to pay, nor will you find anything in this report that says you should put stuff underground. There is stuff in here that talks about some situations in which putting stuff underground is a good idea but there's also a lot of stuff about the problem of manholes that are full of water and that sort of thing.

But back on the issue of willingness to pay. All the studies that have been done -- and Lawrence Berkeley Labs, for example, has acquired -- a lot of these are propriety but they have gathered them all up and done nice summaries. All of those are for a day or less. I don't think even in that situation when you ask somebody what are you willing to pay to not have an outage of six hours that people really have -- I mean, it's so contextually dependent and people don't easily visualize it.

For anybody who is interested I would be happy -- I've now taken off my Academy hat and put on my hat as a professor of Carnegie Mellon. We are very fond of behavioral social scientists, and I have a doctoral student who has done a lot of work in this space where you work hard to bring people to the point that they sort of do understand the context and so on. Is the number you get what they would actually say if their pipes are freezing and it's 12 below and they have no power and they're not going to have it for another 10 days? Probably not, but we think that you maybe can get closer. Now I've put my hat back on.

CHAIRMAN ADAMS: Chris, I believe you're next.

MR. SHELTON: I really like the way the report was structured, so I appreciate the work that everyone did on this.

On your Chapter 4 analysis, I guess slide 9, I'm very pleased to see the mention of system architectural considerations. I was wondering if you could comment on that, and is that included in your overarching Recommendation

or were there other specific recommendations? The reason I'm highlighting it is I think it's something we've highlighted out of this Committee a lot and it's a clear role for DOE. And DOE is in our society really the only body that takes that seriously. A couple universities do it but they're usually funded by DOE to do it. So, what are your comments on that in terms of architecture and how it came out in the report?

MR. MORGAN: I agree. We think it's very important. There is a fair amount of discussion in that chapter. For these overarching things we didn't try to link individual recommendations to agencies and others to those overarching things very much, although in the case of the one for Overarching 4, there is obviously a link there and that's an example of the sort of thing you ought to be doing if you're trying to develop more resilient physical components and systems. You've got to do these models because otherwise you're not going to know how well things help.

MR. SHELTON: Right. And I guess in what I was highlighting in terms of architecture I'm thinking that the state of the art of various components of technology has advanced so much since the system was architected that new architectures can be envisioned. You highlighted a lot of those, the islanding --

MR. MORGAN: I think we're going to hear a lot more about architecture set today. On the other hand, do remember the comment at the outset that a lot of this stuff is very log-lived, which is not to say for a moment that one shouldn't be thinking about these things, it's only a comment on the speed with which -- and we have periodic opportunities to rebuild stuff but then when we do unless you've thought it all through ahead of time -- Florida Power and Light may have thought through how they're going to change some of the stuff in west Florida that they've lost but they don't have time to do a lot of thinking before they start putting concrete and steel in the ground and cables in the air.

MR. SHELTON: Right. And I'm encouraging that that thinking is part of the preparations.

MR. MORGAN: Yes.

MR. SHELTON: And being prepared with the right replacement that drives a change in the architecture over time similar to --

MR. MORGAN: So, if you've lost it and you've got a chance to put up something --

MR. SHELTON: Retirements, right? So, when the retirements come or new investment is required for these other reasons that we're prepared.

MR. MORGAN: Yeah, there's probably not as much of that in here as there should have been.

CHAIRMAN ADAMS: Tom?

MR. WEAVER: -- (off mic) about any further scoping of further visioning. I think it would be important to distinguish those wide area risks that are more vulnerable to the transmission system that might have different risks and different fixes versus the more localized distribution issues that may have different fixes. There's a lot of interrelation between the two, but I think it is important to distinguish that some of the wider area issues may be associated with transmission and they may have different fixes.

MR. MORGAN: Yeah, I agree. I don't

think that particular recommendation is focused so much on the fixes as focusing on getting people to think more about what the consequences of an extended outage are, then you can go back and worry about, you know. I mean, there's plenty of discussion in here about stuff you do at the high-voltage level, but that particular overarching recommendation is much more focused on the issue of raising awareness of the vulnerability.

And some folks who have seen the report basically think we're nuts, but we think that getting more conversation about our collective vulnerability to losing power across wide areas is something that that's the precursor to actually doing anything about it and figuring out who you give responsibilities to to begin to fix stuff because once you've identified some particular issues then you can start talking about who do you get to work on it.

CHAIRMAN ADAMS: Any further discussion on the report? I would like to ask can ICF send us that link to where the report is located and mention that, what was it, Section 7.7 and 7.8 are recommendations that we might be able to do something with?

MR. MORGAN: (off mic).

CHAIRMAN ADAMS: Well, if we just send the link I don't think there's a problem. We can send the link. Can we do that Josh? Thank you. Any other questions on this item? Then I think you're going to get an extra five minutes for our break. We'll reconvene at 3:15. Thank you.

(Recess)

CHAIRMAN ADAMS: Welcome back everyone. Thank you very much for returning. We're going to move on now to panel discussion on the Modern Grid-networked Measurement and Monitoring. This panel actually came about because Merwin saw this as a topic that the EAC didn't know much about. Jeffrey Taft, the Chief Architect for Electric Grid Transformation at Pacific Northwest National Lab has graciously agreed to moderate this panel and offer us some context. So, I'm going to ask

Jeffrey to step up now and lead us forward. Thank you, Jeffrey.

MR. TAFT: Well, thank you very much. I'm going to say a few things in the beginning about this by way of clarification and background because the way this is phrased might not fully convey what this is really about. So, let me start with a little bit of background.

When we think about sensing we start off thinking about the transducer and it transforms some physical variable into an electrical signal that we can use for instrumentation and control purposes, and we've had those around for a long time. We used to just direct wire those into whatever instrument or control we wanted to use. But I guess back in the early 1980s I first heard the phrase "smart sensor" and what that really meant was we took that transducer and we added to it analog to digital conversion so that that analog voltage now became a stream of numbers, we packaged it with a microprocessor so that we could do some digital processing of that stream of data, and we added a communication interface. That collection of things is what we meant by a smart sensor. And since then the processing power that we can package with it, it's gone way up and the communication options have expanded significantly too but the basic idea is still the same. So, now if we want to measure, say, the top-level temperature on a power transformer we can put the transducer in the transformer, we can connect it to the RTU which is where the rest of that stuff is, and we can bring that data back to our control center and stream it into a historian or an analytics engine or display or whatever. And if we have a lot of transformers we can do that again and again and again.

But that is really not the essence of what we're going to talk about. What we're going to talk about is how to use groups of censors together to be able to measure and understand things about the distribution grid that we either can't measure directly or it would be too expensive to measure directly.

So, there's a lot of knowledge about this kind of thing for some other fields. In the field of digital signal processing when we have a large group of sensors that are pretty much the same kind of sensor but they're deployed in some particular fashion, when we want to take all of those signals and combine them together to get something useful out of them we call that array processing. And there's just a huge body of knowledge about that. We use it in sonar and radar, we use it in tomography, we use it in geophysical exploration, for example.

In the field of control engineering we take a variety of sensors and combine the data from those with a model to be able to compute something that we call a system state, a state like the instantaneous condition of the system. Sometimes the state is something we can't physically measure or we don't want to spend the money to have enough sensors to measure every element of it directly so we combine that sparse measurement set with the model and we use that same technique in the bulk energy system. If you're familiar with transmissions systems you've undoubtedly heard the phrase state estimator or state estimation, and what we're talking about there is power state, we're talking about voltages, currents, (inaudible) react to power phase angles.

So, that's an example of combining multiple sensors' data together and that starts to get at what we really want to talk about in terms of network sensors. But there's more. In the defense and intelligence world we have the concept of taking the data from a variety of sources and combining it together and that's known as either sensor fusion or data fusion.

So, we're going to see some of this today and we're going to talk about this in the context of distribution and where distribution is going. So, let me introduce a couple more quick concepts and then we'll move on.

We have the idea of taking a group of sensors mixed or homogeneous doing collected processing and getting information out of that that we might not be able to get in another way or couldn't afford to get. The processing might be central or distributed; if we are doing something peer-to-peer it may be more distributed. But some people would refer to this as virtual sensing. So we may not have the specific sensor that measures the thing we'd like to know, we may use a variety of other sensors and combine that together to make something that gives us what we want to know. Some people call that virtual sensing.

We're going to hear three presentations today related to all of this. Alison's going to talk about phasor measurement units, and in a way that's an example of the array processing approach that I talked about. Kyle Thomas was going to be here to talk about some aspects of that too; Alison has graciously agreed to cover that material. Kyle, as you may know, is tied up with something, I guess there's some weather problem somewhere, I don't know. (Laughter) David is going to talk about the combination of AMI and

SCADA, that's kind of like the sensor fusion thing that I just talked about. Then after that I'll talk a little bit about some architectural issues related to distribution sensing and sensing networks.

So, let's go to Alison Silverstein. You probably know her; she's project manager for the North American SynchroPhasor Initiative (NASPI) and I'm privileged to be working with her on a project for NASPI right now. She's done quite a few things in the past and recently she worked on the DOE's Base Load Study for Secretary Perry, did some work for Bonneville Power Administration on their transmission planning process, has done work for Hawaii, was an advisor for FERC for several years, has worked at a variety of places including the Public Utility Commission of Texas, PG&E, ICF, Environmental Law Institute in the U.S. Department of the Interior. I think she has the same problem I have, can't hold a job. (Laughter)

Anyway, she's going to talk about PMUs and PM applications so I'm going to let her come up and take over and take the time necessary to cover two presentations together. Alison.

MS. SILVERSTEIN: How's everybody? Okay, here we go. Where do I have to point this for it to work?

MR. MORGAN: It's remarkably jumpy.

MS. SILVERSTEIN: I'll say it is. It's very jumpy. This is an example of if this were your mouse you would be trying to fight with it to adjust the (inaudible) action time of the clicker. And that is actually a classic issue with operators, is the processing time and whether things jump before they have the chance to figure out what it is they're responding to.

SynchroPhasor technology improves good reliability because it is sampling at 30 to 60 samples per second and in fact in some cases up to 120 samples per second which is 100 times faster than SCADA can do today. It is time synchronized so it provides real-time situational awareness. The high volumes of data that you get enable insight into grid conditions that is unparalleled and was unachievable before we had PMUs. It gives us early warning of grid events and dynamic behavior, really fast identification of failing equipment and asset problems subject to pattern awareness and pattern recognition which is a challenge because of data sharing. We'll talk about that a little later. It gives us better models of equipment and generators and power system and it will be soon able to create redone secure operator tools and automated system protection.

So, this is an example to show you how PMUs versus SCADA, why this makes a difference. The bottom two panels here are SCADA, so this is bus voltage and line current and you can see that it's sampling solely. I think this is a 4 sample.

The future is scrolling ahead of us here on the right-hand side of the graph. The top are PMUs, and as you can tell there's a lot of stuff going on on the top that you cannot possibly see from the bottom. In some cases the things that are being measured from SCADA don't look anything like what you saw going on in the PMU in reality. So you're getting SCADA measurements where the sample that occurred in that four seconds had almost nothing to do with where the trend of the actual condition on the system was going. That can be a problem when you're trying to design models, when you're trying to predict the behavior of the grid based on information that is very clearly wrong but you didn't know it was wrong.

So, let's talk for a minute about what the elements of SynchroPhasor technology are because we used to think that all this was simple. We would deploy a bunch of phasor measurement units in the field and then magic would happen. Well, it turns out to be a little harder than that.

I'm not even going to try to do the pointer, Granger. I was paying attention. It's always good to have a crash test dummy to lead it off, especially one of such esteemed experience. If you can't make the pointer work I'm not going to take a shot at it. (Laughter) Not doing it.

So, we put the PMUs at key substations and generators then we need a really fast secure-end, high- reliability communications network to ship all the data around town. We need high quality applications and analytical tools, we need technical interoperability standards, and we need business practices that support reliable systems. Each of these are in order of the process by which we discovered how badly we needed them.

The North American SynchroPhasor Initiative is a group funded by the Department of Energy, we've got participation from NERC, from EPRI, from all of the utilities and RTOs that were installing all of these PMUs, and we were essentially bundling the railroad track with the train right behind us moving down the track. So, we got the PMUs in and then we said, oh, geez, we need to move the data around, and then we discovered how hard it was to move this volume of data quickly and reliably with no latency. And then we discovered that most of the applications we had weren't good enough or could be substantially improved once we had enough data to do something with them. And then we had to figure out how to build interoperability standards to assure that all the PMUs did what they were supposed to do. Then we had to do things like fix business practices because it doesn't do any good to have great software if you don't have an owner of the software, or if you don't have a way to get it version- controlled, or if you have PMUs that don't match each other, or if you have somebody in procurement who is trying to save money and gets you the cheap contract for coms out of the substation so that it stops shipping data on the 20th day of the month.

What is a phasor measurement unit? A

phasor is -- how many of you are engineers? Okay, so I don't need to explain this part to you so I'm not even going to try. The phasor is a complex mathematical value representing the magnitude in phase angle of an AC wave form. If I wanted to geek out I would show you graphs that I don't understand that shows sign waves and circles and arrows and stuff. All I'm going to do is show you a picture of a PMU -- this is the classic Schweitzer blue box -- in an array in a substation. The PMU is installed in a substation. That's our substation up there and it's attached to a GPS antenna. Then you feed data from a bunch of PMUs into a phasor data concentrator and you put them from a field data concentrator into a corporate phasor data concentrator. You siphon some of those data off into an historian where you can play games with it or retrieve it. If you need it you ship it up to a regional transmission organization or ISO that's going to do the same things and put it into applications and do great stuff with it.

When we started this, if I really wanted to gloat and if Phil Overholt were here, who is a project manager for Transmission in the DOE's R&D shop, we would show you the 2005 or 2007 PMU map which had about 80 research-grade PMUs, and they were mostly in little tiny pockets of the Pacific Northwest, in BPA's footprint, and around University of Virginia, a couple in PJM, a couple in other odd places. AEP had a lot of the early ones. When I say a lot of the early ones, you had maybe five. That was a lot in those days.

Today we have over 2,500 networked PMUs, many of them were funded by the DOE American Recovery and Reinvestment Act of 2009 (ARRA) grants that came out in 2010, and most of the grants were awarded in 2010 and 2011 and the money was spent between 2011 and 2015. We worked as a collaborative with NASPI across the industry to design a lot of these projects and to help develop all of the priorities and applications.

Most of these reliability coordinators today are receiving and sharing PMU data for real-time situational awareness. Where you see blanks in the map SBP is hurrying to get their blanks filled in as quickly as possible. The red lines here represent communications between major regional RTOs and ISOs that are receiving the PMU SynchroPhasor and shipping it back and forth so we can get something close to regional interconnection-wide situational awareness.

ERCOT. No home bias, but ERCOT has a tremendous system -- way to go, John. They're this patch of green in the bottom. None of you should need me to tell you that if you're on the EAC. Florida is shipping data up but I think probably most of their PMUs were washed away, sadly. Houston doesn't have any PMUs to wash away so that wouldn't have been a problem. One of the great things that I'm happy to tell you about is that if I was able to show you this a year or two from now we are reaching the state where so many companies are finding PMUs of high value in their SynchroPhasor applications that they are now no longer having to be bribed with federal candy or grants to put them in. People are realizing enough value that they're building them into their expansion plans, and as an organic process putting this in, SBP is a great example of that. And when I present Kyle's material from Dominion Virginia Power they and American Transmission Company and Bonneville Power Administration are the three leaders in seeing so much value that they have just built this into -- every time I touch a substation I'm putting in PMUs, every time I build new I'm putting in PMUs.

Here is some of the value that they're getting. For situational awareness and real-time uses, wide area visualization, oscillation detection, I'll talk about that in a minute. Phase angle monitoring which is basically how you tell whether your grid is stable and what's going weird because phase angles show the degree of stress between two points on the grid, and if phase angles start changing too quickly going out of normal bands you probably have a problem that you need to understand. And you can use phase angle monitoring for a variety of fabulous things like Black Star recovery, like bringing on a new generator, reclosing two transmission lines.

Voltage stability monitoring, trending. I can tell you had we had voltage stability monitoring in 2003 we wouldn't have had the U.S.-Canada blackout. Had we had phase angle monitoring we wouldn't have had the U.S.-Canada blackout.

Trend analysis, event replay. We're going to have an example from Kyle about operator training which is a really important use of event replay. Alarms and alerts are pretty basic operating control room tools. Linear state estimation is one of the new frontiers as is fault location. Both of these are incredibly valuable uses.

Offline analysis, phasor measurement unit. SynchroPhasor technology is not specified by name because NERC standards don't do that, but the capabilities of SynchroPhasor technology are embedded in several of the key NERC standards today. And then compliance. You have to prove that you have this capability.

Forensic event analysis was one of the first uses that we ever made with PMU data. When we did the 2003 blackout investigation we had data from one digital fault recorder (DFR), actually two DFRs at Lampton owned by Ontario Hydro, what was then Ontario Hydro. And we drove the entire 2003 blackout investigation on that set of DFR data which is comparable to PMUs.

Model validation, equipment generation and power system. Mostly we started this with generator model validation and then started discovering how valuable -- you could use it for all kinds of equipment models.

One of the highest value uses is identifying equipment problems and misoperations. Because you have this sort of incredibly deep level of detail into how something operators you can start seeing anomalies. Any time there's an anomaly there is something causing it and we can use PMU data in many cases to identify the equipment problems that are reflected in the anomaly.

And for field equipment commissioning. That's mostly a matter of being creative. Don't leave until you use your PMU data to verify that a new piece of equipment you just put in is working the way it ought to. Relay misoperations is one of the greatest causes of protection system failure and of outages across the grid that are sort of routine, garden- variety blue sky outages as opposed to big bad ones. And we should in fact be using PMU data to verify that every single system protection operation, every relay that acted in a protection sense did what it was supposed to do. Not enough people are doing that but we should be.

I'm going to give you another example of how valuable PMUs are. This is the 2011 southwest blackout that started in San Diego. Over here is system frequency, and what that is showing you is what frequency looked like in a heatmap across the entire grid. So, just to be clear, when it started here that's 60; that's where frequency is supposed to be. When it goes down much, when it goes up way high, those are both really bad things.

You don't want me to play it over do you? I should tell you then -- okay, we'll do it. When my kids were young we had this VHS tape of construction equipment and road construction and there was a process during which they blew up sides of a hillside, and needless to say we had it on replay over and over and over again and my boys would sit there and watch the hills blow up. Fun for the whole family. (Laughter) So, this is essentially the grid equivalent of blowing up things with dynamite. This is probably the wrong room in which to say that, isn't it? (Laughter)

So, the southwest blackout happened because a 500-KV line connecting Arizona with San Diego tripped following a capacitor switch out. It took down a whole bunch of nukes. It ended up taking out all of Southern California and significant chunks of Arizona. It was not a good time. I also should tell you in the interest of full disclosure that these data were not created -- this is not real PMU data, this is something called the FNET network set up by the University of Tennessee at Knoxville.

So, here we are losing transmission lines like crazy, and now things are getting low enough that we're going to start to lose power plants, and then we have dropped enough load that everything snaps back in the other direction.

Some of my colleagues who are PMU geeks are very irritated with FNET data because they say for many reasons the FNET is not as good in terms of precision or other stuff. And I say, yes, but the FNET people have only one person running the network as opposed to 80 different PMU owners, and they can collect all the data and have this really great visualization software and they will share it with me. PMU owners are nowhere near as generous in sharing data and we don't have anywhere near this kind of slick graphics capability. So, I grant you that technically that

PMU data are superior and PMU technology may be more swell than FNET, but by golly when you need to do a presentation thank goodness for Liu.

So, oscillation detection. Oscillations, you just saw an example of a pretty unpleasant oscillation. One of the great things you can do with PMU data because it is fast enough to identify oscillatory events and to give you warnings of them is you can build an oscillation detector such as this one that is up on the control room screens at BPA which shows you where you might be having a problem, green good, red bad. And because it has four different cells in each of these markers along each of the transmission lines or substations you can tell by looking is this is zone 1, zone 2, zone, 3, zone 4, which correspond to frequency modes; you can tell what is the cause approximate from each of these. So, this is a nice early warning system.

This is a windfarm oscillation discovery with PMU data. This will look pretty familiar, John. This is out of ERCOT. This is the oscillation starting in the frequency signal. This is the voltage signal. This is a fabulous piece of software because it just looks totally creepy as well as being a not great event. These are oscillations that occurred at a specific windfarm. They started and this entire event lasted over 36 hours, I believe. They continued into the next day. The operators had to reduce -- when something like this is happening caused out of a windfarm or anywhere else oscillations that are sustained can start to damage other pieces of equipment, particularly generators connected to it. And if it gets out of control it can do way more than just hurt proximate generators.

So, the oscillations did not stop until the operators figured out where the source was, which was this wind plant, and then told the owner to back down the power plant by over 40 megawatts. That's real money; 40 megawatts of revenues over several hours. Even in Texas where we've got a lot of wind that's real money. So, what you see here is the oscillation severity did not stop until -- this is almost a day and a half. That's a significant length of time to put your system at risk or to put someone else's, or to be operating with reduced revenue for your own plant, or to put someone else's equipment at risk.

I talked earlier about model validation and model improvement. BPA was the real pioneer in doing model verification and generator modeling. This first one, on this side -- I'm not even going to try right and left -- but on this side is the BPA generator models before they started using PMUs. On that side are the generator models after being validated by using real PMU data about plant behavior so that every time there's an event on the plant you take the event data and you play it through your model of how the generator should behave and your model will predict what the generator ought to do. And if it doesn't do it you need to improve your model. What this is doing is because you get event after event after event you play it through you are gradually improving the model performance every time.

Here's a tip: The blue is the actual event and the red is the model. When they're on top of each other it's a good thing; when they're far apart that's a bad prediction. This may not seem like a big deal because it's only a generator but imagine you're driving a car. You have a mental model of how the car is going to respond when you turn the wheel. If you turn the wheel and you're expecting the red thing to happen, that it's going to respond this much but it only responds a significantly different way, you could be causing a significant accident. If I push this button and it advances three slides instead of only one, then my mental model is being violated.

So, we always need to have an effective model of what we think is going to be happening in the world. That's why this is so important. We can use PMU data for model validation for the entire system. It's not easy, but we can do it, and that's part of the process of every single forensic analysis following a grid event.

Monitoring substation equipment. We can use all of these data for equipment misoperations for anomaly detection. We can figure out when a piece of equipment is going to fail before it fails. In this particular case Dominion -- this is one of the big head-slapping, eye-opening moments for us in terms of one of the great sources of value from phasor measurement unit and SynchroPhasor technology -- can you guys see this? Dominion had PMUs on a CCVT and they noticed that the three phases -- the A and B phases were performing pretty recently, those are the top two, but the C phase was getting all weird and funky. I believe funky is an official technical term. And when they saw it they said clearly something is wrong with this and we'd better go look at it.

Well, before they had a chance to look at it, it went bad. You see that enough times and you think, okay, I can use this as an early warning signal. Here's what happens if it had really gone bad. This photo shows a CCVT that blew up. It sends shrapnel all over the place, it can hurt a bunch of other stuff in the substation, if, God forbid, you have a worker in there he or she could be at significant risk.

So, by getting this kind of warning in advance, by paying attention systematically to every anomaly that shows up and hunting down these weird things, you can in fact take out a piece of equipment that you know is going to fail before it fails, you can order the replacement equipment and do that outage and replacement in a managed fashion on schedule instead of having this turn into a disaster that hurts your staff, hurts other facilities, and potentially could hurt some of your employees.

So, this is an incredibly high value application and we have seen this kind of anomaly detection happen with everything from substation equipment to generator equipment, generator settings, control cards, all kinds of stuff you can spot it.

Here are other examples. Generator settings, governors and stabilizers. Transmission conditions such as local phase and balance and negative sequence current, both of those can harm a generator in a very expensive way. A whole lot of transmission equipment problems and switching problems, and as I mentioned earlier, verifying operation of system protection devices.

ATC has also been a leader in this, as has Dominion and PJM and Oklahoma Gas and Electric are both routinely scrutinizing. They have a day after so they take a 24-hour log spot every single anomaly and run it down. So, very systematically anomaly detection, anomaly detection, anomaly detection; just grind it through.

I mentioned using PMUs to meet NERC reliability standards. These include BAL-003 for frequency response, facility interconnection, reliability coordination, three different modeling verification things, and disturbance monitoring and reporting.

We can use these for renewables integration. PJM and ERCOT have been leads in that, as has been BPA. Dynamic line loading for greater throughput without more capital investment is going to be really huge as we get better information sharing and better diagnostics and big data analysis so that we have a better understanding of what normal is.

Baselining. This is where big data analysis is really crucial. Imagine the difference between looking at your blood on your finger versus looking at it under a high- power microscope, or when someone takes your blood pressure and says, oh, it's high but doesn't realize that you just finished climbing five flights of stairs. Context is everything when it comes to high granularity, unexpected levels of insight into something. So, we need to understand what normal looks like in an entirely different context with a lot more context data to be able to understand whether it's important and why.

I mentioned electrical island detection and blackout restoration. There have been a couple of great examples of that including Hurricane Gustav for Entergy which was able to identify an island around the city of New Orleans and keep a significant chunk of Louisiana online instead of blacking out. And everybody who has PMUs is now using them in drills for system Black Start training and system restoration.

I mentioned system protection operations monitoring. Very few entities are doing that; every single entity should be doing it. We will soon be getting to the point where we can do automated system protection using PMUs to trigger specific actions.

Monitoring GMD, ground-induced currents. You can exactly spot the manifestations of ground-induced currents in PMU data and so we can use this as an early warning sign for a current in-rush and potentially use that as a way to help shut down before a GMD event. We can also very clearly see the impacts of seismic events in these.

Oklahoma. All the Oklahoma PMUs, every time they get a swarm of earthquakes from fracking it shows up in their PMUs. And PG&E and SoCal

Edison could see this too if they were paying attention but they've got better things to do with their data.

Very importantly, this gives us a whole different set of monitoring and analysis and communications that is entirely separate from and redone it to the EMS system so that if you lose your EMS system you have a whole different data set you can fall back on and communications that is in fact significantly more secure in most cases.

What's next? Advanced machine learning, automated autonomous system protection schemes. We're working on getting wide area damping so that we can do things like create an automated RAS scheme to cover the entire Pacific Northwest or the entire Western Interconnection that is self-adapting to whatever particularly disastrous thing is occurring on the grid at the time.

Distribution level uses are not just about PMUs per say but there's a lot of value to synchronize high granularity measurements or to synchronize measurements even if they're not about phasor. The whole phase angle thing takes on a very different meaning and potentially significantly less value at the distribution level, but having highly granular time synchronized data is tremendously important. The other problem for the distribution system is it's much harder to figure out what's signal, and what's noise and because there's so much more going on in the disturbing system probably all of that noise is telling us something and we're just not smart enough yet to figure it out. So, there's a whole lot more analysis that needs to be done there.

Advanced PMU deployment and applications and data- sharing across TOs and RCs. I mentioned problems with data- sharing. People haven't quite gotten over the fact that this is my data and it might be CEII; probably isn't, particularly when someone has a gun who cares about, you know, PMU data. But there's a lot more that we could do if we could get good solid data-sharing, particularly for research and analysis to create all of these terrifically great applications. But we're not there yet and we need to get there. So, institutional. If we went back to that little roadmap I showed with the five flags, the sixth flag is going to be institutional and data-sharing issues.

Challenges. Cybersecurity, multiple redundant, high reliability timing sources. Most of the PMUs today are coordinated by GPS. GPS is terrible. Terrible in terms of reliability. There are so many ways that GPS can go wrong. We need a redundant time source feeding every single substation. And we need data-sharing as I've already whined about.

These are video credits, and that's it. If you will allow me, I'm going to go straight into Kyle's presentation. Kyle sends his regrets. He's with Dominion and he foolishly thought that -- he is busy doing Irma stuff today. So, Kyle took the Dominion logo off of these slides because he thought I might want to merge them into my

PowerPoint. I think it would be a sin for Kyle's great work to be disguised as mine. So, I apologize that the Dominion Virginia Power logo is not on these.

I mentioned that Dominion Virginia Power is one of the most creative and smart and disciplined PMU adopters out there. This is Kyle telling you some of the same stuff I told you. He's an engineer and I'm not so if you have any questions Kyle will answer them.

This is one of our favorite slides. This is in fact an oscillation at the North Anna Nuclear Power Plant. The red line is SCADA and the green line is PMU. So, I rest my case about the value of granularity to reveal what's really going on and whether it can hurt your equipment. This is classic power, so this is an oscillation that starts at 114:50 and runs to 119:10. Four minutes of oscillations at that level when you're yanking a nuke back and forth is a really bad thing.

This is a similar example. This is a

three phase fault. If you looked at this on SCADA which is the red line you'd think nothing was happening.

So, part of the problem of when you get all these data is you don't know how to respond to it, so it's a great challenge for grid operators. One of the things that we're doing is we're using -- and Dominion has developed a very specific operator training simulator that takes in PMU data and uses it to combine all of these things like runtime controls and visualization software and dynamics and all the things that operators need to know, which is why we no longer just hire lineman with bad knees to be dispatch operators today.

What you do is you take real events from PMU data and you feed them into your simulator and then you play them through and let the operator react to them. Considering the number of operators today who grew up as gamers this is looked at as pretty boring for them. You can also design really complicated scenarios and crash the grid. So you can scare the pants off the operator without scaring the pants of the dispatcher in real-time by crashing the grid.

So, the value for training is phenomenal. One of the greatest issues here is that the most valuable real estate within a control room is not on the screens in front of the operators, it's the space between the operator's ears. And that is the part that you need to train over and over again for pattern recognition so that they start getting used to something that is going down and can respond to it calmly with some sense that I've seen this before and I know what to try. We have not yet reached the point where we have enough big data analysis to be able to build good PMU-based operator decision support tools but we hope that we will get there soon once we get that damn data-sharing issue handled.

Kyle gives us another example of SynchroPhasor substation architecture. The secret sauce that Dominion has developed is -- when he talks about standards Dominion is not referring to technical interoperability standards like what

IEEE puts out. These are business operational standards and infrastructure design and construction standards and provisioning and facilities requirements that are part of their basic business practices. They have four standards for SynchroPhasors and PMUs so that they have a standard cookie- cutter design, and a standard set of installations, and a standard set of rules, and settings, and software, and hardware, and checklists to do transmission line relays, transformer relays, PMU panels, PMU settings, substation phasor data concentrator, so that's the one that's in the field as opposed to the one that's in the control room as opposed to the one that they're feeding up to the PDC at PJM.

So, the point is they know exactly what they want to do, they have every single design already made. So, whatever it is that involves a PMU they know exactly how it's going to happen, where it's going to happen, it's going to happen every single time in the same way with the same piece of equipment and the same wiring diagram and the same settings instructions and the same commissioning requirements. Whatever one of these is being installed, if you're taking a relay, putting in a new one and turning on its PMU functionality the field personnel don't leave the substation until every single new piece of equipment has been commissioned and tested and verified using whether it's the PMU itself or whether it is a different piece of equipment and they're using the closest PMU to verify that that new piece of equipment is operating the way it was supposed to.

There will be developing substation PMU standards for non-critical infrastructure compliant and for Black Start. And the Black Start PMUs are -- I mentioned using these for resiliency and Black Start restoration, so anywhere they have a Black Start generator they will be having PMUs at every point along the cranking path for that so that they can verify that everything in the restart is happening when, where, and as they need it to happen. And they'll be using a PMU-based synchroscope which is kind of a new thing. They'll also be putting these into their distribution substations which is fairy novel. I'm looking forward to hearing about that in the near future.

One of the things that DOE is funding and Dominion Virginia Power is participating in is the Open ECA platform. I mentioned the problems with developing software; we've been pushing a lot on open source software within the SynchroPhasor community and we've been pushing a lot on open source because it turns out that you get very high-quality software and we all turn out to have the same problems that we need to solve across the SynchroPhasor community, so there's a great value to sharing and to doing some fundamental shared designs and coding.

So, we've got a couple of really good software shots and a couple of really smart software requirements definers including in this project SPP. You all are partners in this, right, Jay? Okay. And John, is ERCOT in on this one?

CHAIRMAN ADAMS: I don't know the answer to that, sorry.

MS. SILVERSTEIN: Well, maybe the next slide will tell us. So, this is an open source software platform that enables prosecution level use of SynchroPhasor technology and developing analytics for it. It's called Open and Extensible Control and Analytics Platform. The idea is that if you develop the right platform we can start developing a whole lot of other software to park on top of that to integrate much more cleanly and smoothly than with everybody doing -- this is one of the early lessons we learned from interoperability, Jeff, was that the earlier we can develop basic platforms the more quickly we can get higher quality integrated software.

So, these are the partners. Grid Protection Alliance is a bunch of really sharp ex-TVA guys who went off on their own and started developing really terrific software.

And it's almost done. So, people have been coding like crazy. The demonstration began last month, a new version is being released. Dominion, I think, is the first testbed for the software and Oklahoma Gas and Electric. You guys don't have --

MR. CASPARY: They're beta testing.

MS. SILVERSTEIN: Very smart. What he said for those of you who missed it is they're beta testing instead of alpha testing. The alpha tests are I think Dominion and Oklahoma.

What we wanted was to put more of an emphasis on actually doing techniques and tools and less on the sort of integration and API stuff so that we can lower for everybody the cost of software development and tool development and have this integrate more smoothly with a lot of the current phasor data architecture.

This is the usual engineer's incomprehensible bubble platform. So, just bask in it for a moment. And then we'll move on to PMUs, these little dots over here with the classic GPS antenna thing going on. I can tell you that the way the GPS antenna is it's being blocked by the PDC so they'll never get a time signal. That's all I know about it.

But here what they're doing is they're using the same APIs and a lot of the analytics under the hood to feed a whole lot more stuff, so it's going to be more efficient to use common configurations and security platforms and some of the basic analytics before they push it out to the specialty work.

Some of the things that they're developing with this include the voltage controllers, the PMU synchroscope, line parameter calculations, oscillation detection. Oscillation detection says, whoop, there's an oscillation; oscillation mode meter says here's what kind of oscillation it is and whether you should worry about it and it tells you more about the cause.

Synchronous machine parameter estimation is like bringing a generator on synchronously. I don't know what some of these things are but when they roll it out they can bring it back and talk to you about it.

The synchroscope is one of the cool things that they're doing, and this is a physical device that they're using to synchronize generators or an island with the grid. We could tell that already with phase angles but maybe people like to have something physical that tells you what the signal on the screen was going to tell you.

I'm going to let you read that because it's silly for me to read it to you. Are the letters big enough for you guys to see it? I'm not even going to pretend I can tell you what this is about.

Look, it's PMUs. Okay. See, Open ECA -- oh. Look, more builds. Lots of stuff, data flowing around. So, apparently this is all to illustrate that you have an island, two islands, and the -- oh, I get it. When you have delays it messes with your phase angles and we have not yet done all of the analytics and data analysis to figure out just how the level of delay between these phase angles changes the network configuration and the traffic path. But complicated equations to get us there, yay. I just realized this is being recorded. (Laughter) Some of the goals for the synchroscope are about annunciation and making sure that the whole thing works without an ECA because since Open ECA is funding it it would be very embarrassing if it doesn't work.

They've tested it, it appears to work. It appears to be able to do most of the things that they wanted it to do.

And here is -- I think this one builds too. Here are the things that only the engineer who invented it will understand and love. But if you're that engineer and you need to know this, this is solid gold stuff. And don't tell Kyle I'm butchering this for him, please.

This is another user interface for it, and this tells you things like -- I guess they think this is a physical manifestation. So, this tells you whether it's going too slow or too fast and what voltage and frequency are doing.

Look more builds. If Kyle were here I think he would be talking to us about how important each of these boxes are, and I apologize for not being able to do that for you. I can't even figure out what box is going to build next. I'm a total loser at this. (Laughter) And now you know why I'm a consultant instead of a dispatcher.

In conclusion, the synchroscope is going to be great stuff. (Laughter) The other conclusion you should draw with this is you really should hope there's not a hurricane the next time you invite Kyle because he'll do so much better of a job than I could at presenting this.

If you wanted to know more here is where you would go to get some of the stuff. Github is where we actually put up a lot of the software and we have been very aggressively sharing software that have been developed by all of these DOE-funded programs. And some of the volunteer I've got a problem to solve so I developed this little homegrown code, well that's great stuff because if

I've got a problem to solve there's five other RTOs or utilities that have the same problem so we've gotten people in the habit of sharing and it's what has fostered things like the Open ECA project which is really excellent. So, thanks to DOE and for the other participants for funding that.

Who's next?

MR. TAFT: I'm going to say a few words then I'm going to introduce him.

CHAIRMAN ADAMS: Jeff, do you want us to hold our questions until the very end?

MR. TAFT: Yes. I thought we would go through the presentations and then have a general discussion if that's all right.

CHAIRMAN ADAMS: Thank you.

MR. TAFT: So, just a couple of quick words about what you just heard there. You heard a lot of different applications but for the same sensor network. Less obvious is the fact that many of those things required combining information from multiple sensors, so in order to be able to do arithmetic basically on the data from these different sensors the measurements have to be synchronized. You heard her mention synchronized measurements a couple of times and that's why. In a dynamic system if you don't have synchronized measurements when you try to do arithmetic on the data from different places and it doesn't work too well. So, if you had to have a lot of specialized sensors to do all those different things it would have been an awful lot of stuff. Here was a basic sensor network to provide you the observability of this physical system to be able to do all these different things.

So, next up we're going to have David Pinney from NRECA. He is the Analytics Research Program Manager at NRECA, and that means he coordinates and leads software and analytics research efforts at NRECA and with their partners. He has some research projects going on now related to cost-benefit analysis for DER, distribution and transmission system simulation, sensor machine intelligence and modeling platforms. Oh, by the way, the word platform is in the running for 2017 utility word of the year, if you didn't know that. (Laughter)

Prior to that he did some work at a company called Micro Strategy and also did some work on biological models for UCLA Institute for Pure and Applied Mathematics. He has a degree in mathematics from Cornell. So, David, please come and take it away.

MR. PINNEY: Thank you, Jeff, and thank you for having me. I will talk about sensor networks at rural electric co-operatives, particularly distribution co-ops. I like to start with an overview of the co-ops and where they are. This map here on the left is a map of the service territory. The co-ops serve about 42 million consumers in 47 states and those consumers own 840 distribution utilities who in turn own 65 generation and transmission utilities. It's not the majority of the electricity consumers but it is the majority of the land mass in the country, and it's about 42 percent of the nation's distribution infrastructure.

This is a very sparse system. There are not a lot of meters and there are a lot of lines. It's 7.4 consumers per mile, which is way lower than the 34 at the IOUs and the 48 at the munis. What this means is that sensor networks are very popular among the co-ops because they don't want to drive everywhere.

I'm part of NRECA's Research team. My boss asked me to put these slides in here. So, very quickly, we develop and demonstrate new technology for the electric co-ops, we're funded by member dues from those co-ops as well as co-operative agreements from Department of Energy, OE, EERE, ARPA-E, and now co-operative agreement with DAPRA at Department of Defense. We work mostly on software, cybersecurity, and analytics and we partner in every project with vendors, startups, the national labs, universities, and of course the co-operative utilities.

There are a number of emerging grid

requirements out there that we are all familiar with, new generation, resiliency, cybersecurity, et cetera, and there are a number of emerging new technologies that can help with these new requirements and, of course, be focusing on advanced sensors. I think they're the most interesting because the data that come from them then for all these other interesting opportunities and optimization controls, et cetera.

So, where are the co-ops now in terms of sensor networks? It's kind of tough to do this after a long PMU presentation, but I hope by the end to convince you that lower resolution temporally and magnitude not phasor measurements are still very useful right now and will continue to gain lots of new and interesting applications.

So, the main sensor network out there among the co- ops, the one that's most interesting is advanced metering infrastructure. The data on the right is basically penetration rate, and as of 2013 76 percent of all co-op consumers had an advanced meter and 10 percent were going to put it in. So plausibly we're at 100 percent penetration now of AMI among the co-ops. SCADA is used by the majority of them as well.

It's important to talk about the communications infrastructure here. The majority of the meters are talked to or served by powerline carrier, which is a one to five bits- per-second communication technology that I'll talk about in a little bit. But we're starting to see networks with more bandwidths get put in. RF networks, I haven't seen a co-op that isn't piloting one right now. And there's also a lot of demand for fiber to the meter, more so to serve high-speed internet to the consumers but of course once you have that bandwidth you can use it for all kinds of interesting data backhaul.

We also are seeing distribution phasor measurement unit deployments, and there the main desire is from utilities with power quality issues. We're seeing this in oil and gas territory where that industrial equipment offers a lot of harmonic and other power quality issues.

These meters are useful for obviously billing reasons but I'd like to argue that there's a lot of other interesting applications that can be built on top of that data, and I'll talk about a couple. But first, some of the challenges. So, obviously backhaul, PLC, you can't bring back full high-resolution meter data sets from every meter. Luckily that bandwidth situation is getting better. Data storage is an issue, I'd argue not in terms of volume but in terms of how you store it and how you move it around between applications. Cybersecurity, always an issue. Protect the privacy of that metering data.

And we're starting to see interest in the co-op community for interfaces between generation and transmission utilities and distribution utilities. You could do bottom-up load planning if you can aggregate all of your distribution AMI data and you could potentially have it a very high resolution, but of course then you're going between two different utilities which can be a challenge. There's also interest in distribution-to-distribution sharing of the same data.

System integration I think is the biggest issue. On the left here is actually the multi-speak web services bus sets an interoperability standard and hanging off the bus are the typical set of a couple dozen applications that any utility needs to run. There's everything on there from billing to engineering analysis, GIS, what have you. And there are meter data applications in almost all of these systems, but the trick is getting that data to the systems in a way that they can understand. Multi-speak is one approach for a standard here, DSIM, and SIM more generally are another.

But say that all of these problems are solved and you have the issue of, well, what do you do with the data? I'd like to talk about a couple interesting applications in planning and operations. First, planning which is my specialty. So, I'm going to show a couple of applications and these are all built on top of the open modeling framework.

At NRECA we publish all of our planning software applications and results as open source software on www.omf.coop. It's also a production system so you can just go there and run the models. This is built by the co-ops over the past couple of years and also with the support of the Department of Energy. There are a number of different models in there for determining cost benefits, various planning applications, power flow, libraries, and a lot of data-import conversion and visualization capabilities. We've had pretty good uptake. We've got users from 176 organizations. So, it's been fun.

Volt/VAR Optimization has been around for 40 years but is still getting deployed as new control options come on to the market. When we look at VVO planning we start with some inputs. So, AMI data or SCADA data is needed to build the load models that are needed to determine the Volt/VAR demands on the system. And we also need to bring in the circuit model data and we typically convert from CYMDIST or Windmill which covers almost all the utilities in north America. Then based on that high-resolution meter data we can run some dynamic power flows or quasi-static time series technically (inaudible). And we can evaluate for a given set of cap banks, regulators, synchronous condensers, what are the Volt/VAR impacts of these perspective new devices, and then determine the impact on demand and from there convert to essentially cost reductions from a tighter volt/VAR control.

Historically we've been doing sort of worst case analysis with billing data, and SCADA data you can start to look at hour-to-hour impacts at a substation level. If you can get AMI data in there you can look at inside per feeder and inside the feeder impacts for new control solar integration, also of high interest to distribution utilities. Solar integration planning, we start with load and circuit models as before, SCADA and AMI. We pull in based on the utility location weather data from NOAA or Weather Underground which has some user supplied weather station data that's nice to have. Based on those time-varying sensor readings we can calculate overvoltage from solar generation on the distribution system, reverse power flow, and also impacts on the regulation devices and protective devices.

Energy storage is very similar to that with the same inputs. But in this case we also need some kind of forecasting algorithm because we have to decide for a deployment of energy storage how is it going to be dispatched. Basically, what we do is we blind ourselves to part of the sensor data, learn on it to determine a forecasting approach, and then develop the dispatch scheme. Then we can see how is that going to move load around which will then have an impact in peak demand or demand in times of different tariffs, another thing that is very hard to do with monthly-only billing data.

Probably the most sophisticated thing we're working on right now is models for optimal resiliency. So, we take all the same inputs as before but we include damage maps from specific location wind damage, water levels, et cetera, looking at shake maps for earthquakes. We're working with Los Alamos to build a fragility model to essentially say, well, based on an extreme weather event what parts of the circuit are most likely to be damaged. And then from there we're also working on them with an optimization model that says, okay, you have a given amount of money for new switches, undergrounding, distributed generation potentially; what is the optimal deployment for that given set of money to improve the resiliency of the system? And it actually does work. We are also working with the GridLAB team at PNNL who help us calculate what new switching and control actions are needed for that new optimal system.

So, that's some of the planning opportunities that we've seen in the research area. On the operations side, meter reading typically pays for an AMI deployment but then in the chart on the left there's this sort of long tail of other applications that can be derived from the same data set and the same network.

Here really the only barrier is getting the integrations done with the other systems. So, on the right, same survey, basically shows there's a lot of integrations that are not getting done because they're expensive, but there's also a strong demand to eventually get that all integrated. If you can get your AMI system integrated with your outage management system, well, then you can start to ping meters as part of your outage restoration process. And there are of course many other examples.

On the research side in operations NRECA and the co- ops are working on grid state and it's a system for passively monitoring and analyzing data from utility system works through networks taps basically, collects all the network data and from there derives the system state. Originally funded by DARPA which was introduced in the cybersecurity application of this technology, we also hope it will be useful to provide situational awareness, so a complete state of the current system.

Looking further into the future, where do we think the big opportunity is? We think it's in a kind of tight coupling of the operations and planning tools. Once you can easily move data back and forth there are a number of fun things you can do. So, on the operations side potentially you could do fast lookahead and you could look at a set of simulation scenarios about what will happen in the next five minutes, ten minutes, one hour. On the planning side if you can get all that sensor data into your planning tools easily you can start to look at -- well, the BPEA model validation was an example but there are a number of other models at the transmission and distribution scale -- wires, transformers, loads -- that it would be nice to continuously check against the sensor data instead of kind of build once and then use and carefully update by hand.

So, in conclusion, sensor networks, particularly AMI, are all over rural America right now. Data is integrated, will become even more integrated into planning and operations tools. And we're excited as network bandwidth increases about the kind of new and fun things you can do with these networks. That's my email address. Thank you.

MR. TAFT: So, very good. I'm going to talk a little bit now from an architectural perspective and I'm going to focus on distribution in particular in terms of sensing and sensing networks. The way that I'm going to do this is I'm going to focus on a particular scenario and that scenario has to do with increasing penetration of distributed energy resources into the grid and use of variable energy resources, renewable resources in particular. This is a topic of some considerable interest in a good significant chunk of the industry. We've been doing work with a number of the state commissions on preparing for this in their grid modernization plans.

So, this is diagram is a depiction of

the problem domain. We use things like this to sort of lay out what are the kind of key elements we have to be thinking about. So, you see two substations here in the two corners and there is a feeder that has an intertie between them and just a whole variety of kinds of things attached to the feeder.

So, we see some of that happening already and certainly people are anticipating a lot more of this. The pace at which that will happen varies from place to place and the degree to which it will happen certainly varies as well. But in a lot of the modernization efforts that are underway now this is roughly speaking the type of model that's being contemplated, and a lot of this is driven by penetration of solar in particular but also local choice and use of microgrids and the potential for using various assets like buildings and residences and so on as partners in operating the grid.

Some of the trends that you're well aware of have to do with what happens when you start to change from traditional generation to these forms. Among the other things that we get with them are also potential problems with balancing and stability at the bulk system level and introducing fast dynamics at the distribution system level which introduces potential problems with things like voltage regulation. Some of that volatility at the distribution level can be reflected back up to the bulk energy system level as well creating more problems there.

Another thing that happens in a situation like this is that we see the dynamics getting faster and faster at distribution. Used to be in the 20th Century grid that except for protection nothing really happened much faster than about five minute-type timescales and longer. So, we had a lot of person-in-the-loop management distribution grids. In fact, if you've known any of those folks who were operators they would tell you things like, well, nothing happens on my grid unless I initiate it or I allow it to happen. That's okay at those slow timescales but when we start to have things happening a lot faster that's not supportable going forward.

And we're increasingly seeing the connection of more and more smart devices, and some of those smart devices want to interact with the operation of the grid. Some people project very large numbers of them when you include all of the AMI and all of the smart loads and distributed energy resources they can become potentially quite large. No one's reached huge numbers on those yet, but we see those trends moving in that direction and certainly people are concerned about that. So, we're moving too fast system dynamics. Moving too fast are sample rates to keep up with those dynamics and getting a lot more sources of data, or at least potential sources of data that we may have to deal with.

Because of this change at the distribution level the relationship between distribution and bulk system is changing too. In the past we thought of distribution as being essentially a load that would be connected to transmission pretty well behaved, but what we're going to have to think of in the future in these visualizations, these scenarios, is that it will be more a matter of responsive load plus acting like a generation tie point. That means the relationship between how the distribution system is operated and how the bulk system is operated will change pretty significantly.

And you notice all that connectivity there. All those things that are connected especially by way of the internet. And by the way, you notice those two guys lurking in the two corners, see those guys? One in the upper left and lower right. You probably don't know this but the official hacker uniform is a hooded sweater, a mask, and you sit in a dark room with a laptop. There's an IEEE standard for that.

(Laughter) Nevertheless, that's something we have to consider a lot these days that we didn't used to consider in the 20th Century grid.

So, we've got all this connectivity,

we've got all these new devices that can impact the operation of the grid and that's going to lead to new roles and responsibilities. That has an impact on how we handle sensing and measurement at the distribution level. We could take the approach of saying, well, you know the balancing authority or the system operator is somehow going to have this ability all the way down to those edge devices at the distribution level and there are some places where people think they would like to do that. But architecturally that's a problem in terms of scalability, in terms of cybersecurity issues, and in terms of roles and responsibilities with regard to who has the responsibility for safety and reliability at the distribution level.

So, more likely we're going to see this evolution where those entities have a relationship that hasn't existed in the past but those roles are going to mean that the distribution operator needs to do more management of the distribution system assets, and that means more observability, more measurement, more ways to know what's going on than they had to have in the past.

So, we think that if you look at the relationships among the various entities you'll see this kind of structure evolving where we have something that you've heard people talk about, distribution system operator which is not a thing, it's a set of roles and responsibilities mostly for distribution operators, evolve so that there's a relationship that allows the distribution system operator to come to an agreement with the system operator about what happens at that transmission distribution interface. And then the distribution system operator has all these responsibilities for managing everything off to the left there.

There are some variations on that that involve some bypassing and so on that are likely to happen in the meantime, but that DSO thing that you probably have heard a lot about, even though some people focus on the idea that you heard from New York about, well, those are going to operate markets at the distribution level for DER, that's not really what this is about. It's really about managing all these assets at the distribution level and managing them in a way that's coordinated with what happens at the system level. And that is the core reason why in these scenarios there would need to be a lot more measurement and observability of distribution and that means faster measurement and synchronized measurement.

Some of the other things that we know people are thinking about that we think are probably important trends are changing from a very monolithic grid to something that's partionable, using the concept of layers and platforms -- oh, there's that platform word again -- to restructure the way certain things are done, moving from something that at the distribution level had been sort of pretty rigid and brittle to something that's more cushioned and tensile. So, what does that mean? That means putting some buffering in at the distribution level. That means using storage at the distribution level to help the distribution grid absorb shocks a little bit better than it can now. Moving from weak observability, meaning not much sensing at all to strongly observable. Most of our distribution grids don't have a lot of instrumentation. And then making sure everything is well- coordinated, and we've had gaps that have been developing over a number of years. So, the DSO models are largely about dealing with a lot of that kind of stuff.

Where are we now? You heard some of this already. A lot of our distribution systems still have very little or even no distribution SCADA. Not all of our substations have substation SCADA. A lot of our sensing is low-speed and low-capability and very minimal sensing of actual grid variables. A lot of the older AMI that has already been deployed is not really very good as a sensor network. It's good as a cash register but it hasn't turned out to be that good for sensing. And part of the reason is that the way that those older AMI meters did sensing was not really thought through in terms of supporting advanced grid operations, and part of it was because the communication networks that came with them were weak. So we've had a real problem with that and in a variety of distribution utilities they tried to take the AMI communication network and sort of grow it upward to become a distribution automation communication network. That hasn't always worked out very well.

So, in the current efforts on modernization that we see across the country distribution utilities are looking at significantly redoing the communications, and that's one of the early decisions that has to be made. And when we do this work with a bunch of the commissions that we're working with now they're always asking us what should be do about the communications? We're getting all this input from the utilities, how should be think about the communications for all of this going forward?

A couple of other problems we have. Don't always have very good system models for distribution. In other words, we don't always know how things are connected to distribution. That might sound funny but if you haven't been involved with distribution trust me, you can find out -- utilities will tell you that their connectivity models may only be 50 to 80 percent accurate. There's one very well- known utility that I'm not going to name that told me a while back that they found out their model was only about 30 percent accurate.

Those connectivity models are the context that you need to interpret the sensor data and to determine control actions. So, if you don't have good models you have a real hard time doing very sophisticated thing with either sensing and measurement or control.

Another problem we have is sensors themselves can be expensive or not expensive but installation of them is expensive. It would be really nice if we had some drive-by way of just shooting them out of an air cannon from a truck and get them to stay on the utility poles. But even if the sensors are free going up the pole to install them can be cost-prohibitive too. So that's a little bit problematic to say, well, we're just going to magically have lots and lots of sensors out there, much as we would like to do that. It's not necessarily practical.

We have a lot of sensors now. These are a couple of standard ones that have been around for a long time and there are quite a few of them, and there are more coming because people like to innovate in this area. But frankly, it's the other issues that are probably the bigger ones than creating new sensors for distribution.

By the way, if you don't know me here's a good time to find out that if I don't produce at least one iChart for presentation I'm not doing my job. So here it is. This is part of the work we're actually doing with GMLC in the sensing and measurement strategy project to develop a definition of what we mean by extended grid state mostly for distribution. Grid state, we typically think of especially at the bulk system level as being power state, right? Voltages, currents, real and reactive power, and phase angles.

But really if we want to understand the

instantaneous operating condition of the grid there's a lot more than that that we need to know. So, all of that's in here, but so are a whole lot of other things. And the purpose of developing this representation is to say let's think about all the things we would want to know, we may choose that we're not going to measure some of them because it may turn out to be too expensive, but let's start with an understanding of all the things we want to know so that we can develop an observability strategy for distribution and leap to then what would be a sensor network design for a given distribution grid.

Some issues to think about when we do that. There's a sort of control system point of view which means that we want to understand the grid state. This is an important thing to understand. When you're dealing with a dynamic system of any kind you would like to be able to get snapshots of that state. All of the knowledge we have about how to manage complex systems, dynamic systems, and control them and so on pretty much assumes that we're going to get these snapshot versions of the system state. And you can deal with the fact that maybe not every measurement is aligned but it works a lot better and a lot more simply if the measurements are aligned in time, that means synchronized measurement. It doesn't necessarily mean SynchroPhasors, although it could be. And you heard Alison mention a synchronized measurement is really a thing that we'd like to try to achieve if we're designing a sensing system for distribution.

At the instrumentation level where we're looking at the actual AC waveforms there are a whole lot of things to be concerned with that we have to think about in terms of how we would do the measurements. And it turns out that a lot of the things that we would like to be able to do by way of things like fault detection and characterization and so on, on three phase feeders work pretty well if we treat them in terms of phasors and SynchroPhasors which we typically have not done in the past. There's a whole body of knowledge about how to do fault characterization and pre-fault characterization using phasor representations at the distribution level that we have not really made much use of because we haven't had the measurements to support those approaches. So, we could do a better job if we had better measurements in that regard.

The trick here would be to think about how much of what kinds of measurements where would we want to have and then how would we share that data. And you heard something about data-sharing in the last presentation. One of the problems we've had in the past is that sensors and communications systems for them have been kind of siloed with applications.

I can tell you that I work with a number of utilities that had multiple communication systems, one had eight different communication systems non-converged, and they were tied to specific applications. We try not to do that now but we still have this problem of vertical siloing and that leads to tremendous integration problems too. If we have data from one set of sensors where that kind of belongs to one system and we have a different application over here that wishes it had some of that data, now we've got to have some kind of integration between those systems to be able to share that data. When we do that that's expensive in itself and it's brittle too. If we change one of those applications those changes may end up impacting or rippling through all the rest of the integration. So, it would be nice if we could figure out how to deal with that problem and change that architecturally so we didn't have that kind of situation going on.

So, some implications for all of this. If we're going to be thinking about what's the way to do distribution sensing going forward in these scenarios we need to think about the electrical measurement part, and that means we have to have reasonably fast waveform sampling because of the fast dynamics that we're going to have to deal with. If we're going to deal with phase angles and phase angle differences, at the distribution level those are pretty small differences and the measurements are kind of noisy, as you heard Alison say.

So, in the bulk system phase angle differences may be fairly large. On a typical feeder at the distribution level if you look at the phase shift from end to end over, say, a 30-mile long feeder it might only be a matter of a handful of degrees. So over much shorter sections it's much smaller, and that's a problem in terms of precision and accuracy.

We mentioned timing and synchronization. If all of our sensing is in the substations maybe it's practical to do the kind of timing and synchronization we've done in the past, but the fact of the matter is that at the distribution level we really want a lot of that sensing to be out on the feeders. So, now we've got those devices out there and we've got to synchronize them out there and we probably have to rely more on the network to distribute timing and synchronization information.

One of the ways to architecturally deal with some of the problems is to break up those vertical silos and take the measurement and the communications and make them an infrastructure later. So, vertical silos, chop them up, layerize some of this stuff, make that into -- here we go -- a platform as part of the grid infrastructure itself. We can do that in such a way that we can decouple the applications and that solves a lot of integration headaches, especially for the real-time operations. We can have distributed applications very easily because we can make it so that any application can connect to this sensor network, and if it's authorized receive data from any of the sensors it wants.

That's essentially how we've planned things for the PMU networks. In fact, if you look at the way data transmit works in the WEC system it uses the network as a publishing and subscribing mechanism to be able to send data to multiple destinations. And the network does all of the work for that, the sensors don't have to know anything about it.

So we need some redundancy for resilience purposes, we need to be able to potentially send data from these sensors in real-time to multiple destinations; there are ways to do that. We need not just sensing of the grid parameters but sensing of the grid topology. Remember I said we don't always know how things are connected, those models aren't always accurate? It would be nice if we had real-time means to continuously update the connectivity model for our distribution systems. We're not very good at that.

Then we need approaches to actually design these sensor networks so we needed a methodology, an observability strategy, then a sensor allocation methodology and tool leading to the development of sensor networks that can be customized for a particular distribution grid by either optimizing in the sense of saying I've got a fixed budget, what's the max amount of observability I can achieve, therefore, where and how many and what kind of sensor should I place on my system? Or say how can I minimize the cost of achieving a given level of observability?

So, we didn't need much observability in the 20th Century. Dynamics weren't fast except for protection and we took care of that. But we're heading in the direction where it seems like we're going to need a lot of that for those areas that are going to have the high DER penetration. And that has a lot of implications for the way sensing of the measurement would be done, and we should think about the sensing and networking part of that as core infrastructure.

By the way, that removes that from the typical BC analysis and puts it into the domain of best fit/least cost which is another advantage to treating things that way. And I will say for those utilities that don't have a lot of automation in distribution getting this done is a pretty heavy lift. So, it's not a simple thing to say, well, just go out and put in these new distributions.

So, that's a major investment and that's part of the modernization effort, and we see a lot of distribution utilities looking at that very hard. If you look at those modernization plans that are being published now a lot of that is focused on so what does that communication network look like and a lot of people have realized it needs to look like an infrastructure layer with a lot of capability so that we can have a sensor and observability strategy which is future- proofed and if we need to change it over time we'll be able to do so.

I'm going to stop there for those comments. I think now at this point we should just open it up to general discussion.

CHAIRMAN ADAMS: That was pretty overwhelming. I don't know if you all are aware of it but that's huge. Thank you very much for the presentation. I'd like to open it up for questions. Mladen, you're always willing to start out.

MR. KEZUNOVIC: I have to say something

otherwise I'm going to go to sleep, it's getting late. All right. Great presentations, great work by NASPI. Technology is moving forward and for the reasons we all understand. I would like to comment on two or three things, and you may interpret comments as questions if you wish, but those are kind of overarching comments.

One overarching comment is tying this technology to the resiliency. We had this report and I was mentioning in the comments for the report on resiliency that it would be nice to pinpoint reasons for resiliency not being at the level where we want to be so that we can somehow benchmark the technologies. So, if we have a synchronized measurement, technology -- and I like that by the way more than SynchroPhasors because SynchroPhasors are only one feature -- where would the technology help resiliency?

Now, one can always say there are so many applications that this technology fits, but it's a reverse question whether those applications exist in every place and where do they exist. You can say oscillation is an important application but some utilities may not see the issue of oscillations. If it's a protection issue, protection is a fundamental issue. If we have fundamentally something that needs to help the protection, like systemwide protection, then that's maybe something that we should point out.

So, I think those high-level goals, how we relate this technology to resiliency would be good to have. And I'm pretty sure there are all kinds of reports out there. It's out there. It just maybe needs to be summarized at one point in time. So, that's one comment.

The other comment is the maturity of the technology. And what I mean by that is if DOE is looking at this and the rest of the world is looking at what DOE is doing, it would be nice to know at some scale of maturity where this technology is. And I'll illustrate this. It's not anymore a PMU, it's the end-to-end. It's everything that supports that particular infrastructure including communications, including everything else.

But there is also a core question, when we're measuring something like phasors and we're looking at electromechanical oscillations in the system, and we're looking at electromagnetic oscillations in the system, the phasors are not defined for certain dynamic conditions. So, when we're talking about extraction of a feature, for example, like a phasor, we need to know what is the maturity of that particular technology estimating a phasor under articular dynamic conditions in a system. And I think personally there is some way to go there. So, that fundamental because tied to the synchronization itself that is clearly having some issues, the measurement itself needs to be resolved as a fundamental problem.

Incidentally, I made this comment at NIST when I was on the review panel for their Measurement Division because the NIST is a place where we would like to see the reference for difference measurements, including in this case a phasor.

And the last comment I want to make is something that will tie the new technology, synchronized measurement technology, to the upgrade in the legacy systems. The legacy systems are EMS/DMS. If you're running transmission it's EMS, if you're running distribution it's DMS. EMS is more mature than DMS.

But adding technologies like this one that are fundamentally changing the capability of EMS functionality and DMS functionality has to be viewed in a more strategic way. Are we adding things and patching the previous technology, the legacy technology, or are we really facing a question of the new conceptual design of -- call it now EMS/DMS, it may not be called that anymore, it may be called something else.

I think that's very fundamental to using technology, applying technology. The part of this comment is that EMS was invented as a concept 50 years ago and hasn't changed much until today. DMS was lagging even though the efforts on the original DMS were early on when EPRI did studies in the '70s but somehow the technology didn't pick up so we had DMS development later on but still, a long, long time relatively around.

So, those are some overall comments. And, again, those are comments. But if you can add to it something to either confirm from your angle that those issues are maybe there or somehow put them in some other context of a global view that would be appreciated.

MR. TAFT: So, first I think those are really good comments. I appreciate that. Some of the things that are involved in all of this we have actually spent some time doing some analysis of where they stand in terms of feasibility by measuring the level of adoption that they've reached. So, there's a project that DOE has sponsored called the DSPx Project that focused on a lot of these technologies for distribution. Part of that, the second volume of it, is a snapshot of where things stand in terms of their availability and use which is getting at some of this but not all of what you said in terms of the maturity of those technologies.

Some of the technologies like what I talked about in terms of communications layer, that's actually standard, off- the-shelf technology that exists and is used in other applications so we know that that's widely available. But some of the ways that measurements are done, as you pointed out, still have a ways to go in terms of maturity. I think it's a good point that you raise and we're aware of that.

We're also aware of the legacy to new future issue. This is not a greenfield situation, we're not a frontier nation so we have to rebuild the airplane while it's in flight and we understand that you can't just despite these pictures that we draw just say, well, we're just going to do a step change from where we are. No utility can do that. So, part of the work that we don't talk about here has to do with figuring out, so, what's the roadmap look like to make the transition from where we are to where that's going to be, and how long is that going to take, and how much is that going to cost, and how should the different pieces be financed, and all of that. So, I think your comments are very well-taken.

MS. SILVERSTEIN: So, Jeff gave you the engineer wonk answer and I'm going to give you a different answer. First off, with respect to maturity I want to point out the very distinct difference between the maturity of a technology as a technical idea and the maturity of a technology as an adoptable thing. The importance of that, you may recall the graphic I put up that showed the flag steps in SynchroPhasor technology adoption. You start with the PMUs and then the communications and then the applications and the technical interoperability stance and the business practices.

Even with all of that -- and DOE spends a lot of money mostly funding to develop the technology of the thing. And then if we're lucky then they do the applications and then maybe they get to the point of let's do some standards while we're at it which was the big insight with the whole ARA smart grid investment. But very little of the time that's when we end up with sort of the valley of death for a lot of technologies because most people never figure out how to get the technology -- the technologists never figure out how to get it to the actual adoption in the hands of people who actually see value and want to use it. That strikes me as the maturity for adoption purposes, is a significantly greater challenge. So, I wanted to draw that distinction.

By the way, the other complication, Flag 6 if you will, for SynchroPhasor technology and the vulnerability of every other utility application as we get into more complicated dynamics, fast-changing, data-intense uses within the utility space, within grid space, is most of the data that utilities collect today sucks and you end up with people spending a fortune to collect staggeringly bad data and ship it around the country. Then they look at it eventually and they say, geez, most of these are zeros instead of real useful numbers that I can do useful analysis on. So, you've adopted something and you're still getting crack. Gosh, that turned out not to be so good.

So, we now are belatedly like many others in the era of big data discovering that that is what we now need to work on that nobody understood adequately before and that's going to be one of the challenges for making SynchroPhasor data high value as with AMI data; there's an awful lot of AMI data out there however there's fewer of it and it's more -- you can still cash the check or issue the check using AMI data.

So, that is the maturity question. The other thing that you raised was about time SynchroPhasors and more broadly measurement and sensing technologies to resiliency and how can these technologies help resiliency. I'd like to suggest two things. One of them is there is the use of the technology for making the grid more nimble and measuring and watching stuff and trying to keep it from happening as badly. The other is for integration purposes I have been hassling Jeff over the proposition that much of the work that we've been doing on measurement and sensing and the extended grid state is still way too grid-centric. It's like if you didn't pay for it and if you can't control it it's not real and it's not your problem, and in fact customers are walking away from you every day because, goddammit, it's their stuff. We need to be significantly more responsive to that, and a lot of the resiliency work -- I'm on a soapbox now, sorry -- that we need to be doing is figuring out what the heck is going on out there behind the meter and understanding and using all of these measurement and sensing technologies and all of the applications and analysis attached to it, figuring out what is going on out there that you're not in charge of and that you can't control, and how can you develop ways to be more responsive to it and compatible with it.

A lot of the things that we need to be doing for resiliency are helping customers survive because the grid is going to go down no matter what. We had a wonderful presentation from Granger about all-hazards resiliency. And God, there's a lot of hazards out there. So, I think we should be investing more money in energy efficiency and in pass of solar and things like that so that customers can survive the inevitable things that are going to go wrong more effectively instead of just -- and doing not just hardening because, you know, ice storms and floods and hurricanes make it pretty clear just how ineffective hardening can be or how hardening can make something worse.

So, we need to be putting a lot more of these measurement and sensing things into how do we design graceful failure and help customers survive the inevitable failures. Sorry, that probably wasn't the answer you wanted.

MR. PINNEY: Just quickly on technology maturity. So, every engineer I talked to of course wants the perfect DMS system in place, all of their data perfectly integrated in there for all of their operators, but the technology is just moving too fast for them to achieve this vision. I've seen in the last couple years people go from making fun of automatic vehicle location -- ah, why do I need to know where my trucks are -- to being really excited about finally seeing their trucks and their meters and their wires all on the same map, and it makes their operators' lives a lot easier.

So, I expect we'll see five new applications pop up and that will be have-to-haves. And until those things stop coming you're not going to have a perfect combination of everything. The very highly skilled IT-centric utilities, they have beautiful environments but it's hard to attract the kind of IT talent that can cobble all these systems together.

On the plus side, the networking techs getting cheaper, IP networks are becoming more prevalent; it's less of these custom AMI and mesh things out there. So, hopefully that will make you just buy a sensor, plug it in, and it works with all your stuff a reality. You know, the internet of things. Right now those internet of things platforms are very, very expensive and it remains to be seen how well they can deliver on their promises, and there have been some stumbles.

CHAIRMAN ADAMS: Granger, I think you're next.

MR. MORGAN: So, Alison I really enjoyed your talk but I am not going to ask you a question. I am instead going to ask Jeff. So, I've got all this instrumentation out there and I'm getting phasor data in, and it's all got timestamps but it all comes in at different times, so I will never in the short-term, meaning in my lifetime probably, get a single snapshot of the entire system as it is right now; it will always be stuff that's delayed with different amounts of time delay. And I know that David's boss, Craig Miller, is talking a lot about how I extrapolate and deal with this.

You want to talk a little bit about the problem of doing state estimation when I've got stuff that doesn't represent the current state of things where some of the system could have changed quite a bit since I last got a measurement? I mean, am I missing something or is there a real problem here?

MR. TAFT: There's a problem here but it's not insurmountable. At the bulk system level with PMUs currently the way we handle this the measurements are timestamped and when we need to combine measurements, which we frequently do, that's done in a particular application. Sometimes it's actually a system; that's what the phasor data concentrators essentially do is match up timestamps so that you have a collection of data that is time-aligned.

MR. MORGAN: But that's what things looked like some time ago.

MR. TAFT: Wait, let me finish.

(Laughter) Control theory deals with latency in measurements. We know how to deal with those things and we know how to understand the impact of the dynamic (inaudible) the system if there is latency in the measurement system. We do that all the time. If there is too much latency in the system we can end up with a feedback control that becomes unstable. The question is whether the dynamics are such and the sampling rates are such that we're going to run into those stability limits or not.

With most of what we do we don't really have that problem of running into those stability limits. One of the things that we're doing now to deal with this at the bulk system level is to take advantage -- you know, we've always in the past said, okay, we've got this control system -- we don't do a lot of real fast closed loop control in the bulk system. If you look at the way we do that it's mostly model predictive control. It's actually kind of slow. The protection stuff is what runs fast and where we want to head to is faster closed loop control.

But dealing with the latency means different kinds of control compensations for one thing, but the other thing it means is we've typically said the communications system is a given, its characteristics are whatever they're going to be, and those characteristics may be variable latency, but the way that almost all of our communications networks are designed is that what's called the control plan and data plan were embedded in the routers and switches and we couldn't do anything about that. In the last number of years that's been changing through a technology called software-defined networking which separates those two layers so that you can have an application that is able to manipulate the network to deal with those variable conditions.

The idea here is that you would use software-defined networking technology merged with the control technology to do two things: Inform the controller of what the latency looks like so it can adapt its control algorithm to make sure it stays stable, on the one hand. And on the other hand allow the controller to tell the network I want you to reroute to get me a faster path because the one I was using is suddenly becoming insufficient in terms of latency.

So, that takes the communication network and the control and makes them partners in an interactive way which is not something that has existed in the past, and that's an approach to getting a better overall closed loop system than we would have had before. We have the capability through high-speed networking to be able to do sufficient low-latency communications to deal with all the dynamics we have to deal with. It doesn't mean we always do it now, but the technology is more than capable of it and where we have sufficient networks we don't have that problem. We just don't have those networks uniformly in place and therefore we end up with latency problems, and therefore the controls have to be designed to deal with that.

If we have, by the way, misalignment of

the samples there is a body of control theory to deal with that too; we don't typically apply it very much because it hasn't been that necessary. When we move toward faster closed loop controls it will be. But we're not at a loss for things to do to solve this.

MR. MORGAN: I guess I'd buy all of that as long as things are in reasonable shape. If we're going to Hell in a handbasket and we're trying to use this stuff to avoid that then I guess maybe I have my doubts. But, David, do you have any perspective on any of this?

MS. SIVLERSTEIN: Let's try my perspective if you could, please.

MR. MORGAN: Yes.

MS. SILVERSTEIN: And that is that one of the benefits -- yes, networks are significantly faster today than they were before, and yes, we are moving to ways to compensate for latency. But the value of having multiple redundant PMUs and networks is that each PMU is able to see a significant hunk of the grid and we know from increasing study that we have different pairs of PMUs that are essentially redundant. So, if I have visibility over A and B it is less necessary that I see C, D, E, and F.

So, there are different combinations that you can fall back to and get very good visibility that is not as good as having visibility into every single PMU that's out there, but good enough to make some of the key decisions you need to make in real-time and to get the kind of situational awareness that you need to address a lot of these critical questions. Also, one of the ways we handle latency is to drop out stuff that doesn't come in in time. Of most of these networks latency is less of a problem than it used to be in terms of effectiveness.

The other point I want to mention is that one of the things we're doing is working on probing the vulnerability of different applications to different types of data quality problems including latency. How many PMUs can I lose before I don't trust the answers that this is producing anymore? How much late data or how timely does the data have to be for me to have a high quality, high trust answer from this application and to start putting like a marker in the dashboard that tells you this is a credible answer, this is worth acting on versus the amount of data that is coming in is no longer -- that matters for this application I'm getting enough data to trust this answer and to act on it, but when it gets to below 95 percent or 90 percent that's no longer good enough to make the right decision, look for other tools. So, both of those are important markers to help that decision.

Did you want to throw in on this one?

MR. PINNEY: I think the key is giving operators tools they trust. In theory everything works great in the model and if we had perfect observability we could just run everything from the model, but then we would run into all the problems we have with power flow and AC optimal powerful. But I don't think you can argue against giving engineers, lineman, the ability to ping a meter, you know, to see if something is hot. You can't argue against wide area visibility.

And then the research challenge I think is how do you increasingly develop the rules that can be used for control that don't need that kind of human judgment and that kind of most pessimistic look at it, be careful, and then move?

MR. MORGAN: So, I'll stop, but I like Jeff's idea of making the communication system a bit dynamic as well to address some of these problems.

MS. SILVERSTEIN: We can't actually wait until that happens. We kind of have to keep the grid going in the meantime with the data -- we can't wait until that happens and the cost of replacing those communication systems is non-trivial. So, we have to go with the lower-rent, get 'er done solutions now.

CHAIRMAN ADAMS: Rolf, I'm going to ask you to go next and then I'm going to ask some questions. What I'd like to do if everyone is agreeable is transition to an internal discussion of what we're going to do with this as the EAC leaving the panel stuck up in front of us. Is that okay with the panel to ask them to participate in that discussion? Does that meet with general agreement?

Rolf, please.

MR. NORDSTROM: Rolf Nordstrom with the Great Plains Institute. Thank you all three, those were great presentations. My brain is full.

I have sort of an unfair question to ask you because really none of your presentations were focused on distribution system planning per say, but it feels to me like we are asking distribution system planners to plan for an inherently unknowable future system. I think that planning exercise used to be a lot easier. I'm just wondering if you have an opinion about what the best tool is out there for distribution system planners.

In the work that we've done in Minnesota the conclusion we came to was that scenario planning might be the best option to sort of bookend possible futures and sort of do the best you can from there. I'm just wondering if you all have an opinion about whether or not that is a good tool or if there is another one that you're thinking of or know about in terms of approaching distribution system planning.

MR. TAFT: So, I won't give you a direct answer, I'll give you a reference to maybe help with the answer. I mentioned a while ago the DSPx Project is something that DOE sponsored. There's a website that has all of the results on it; doe-dspx.org I think it is. There are three volumes of documentation on there. One of the volumes has an entire section about planning -- this is all about distribution planning -- and an analysis of a variety of existing distribution planning tools and what they can and cannot do and where that's headed.

So, rather than try to give you an answer because I'm not much of an expert on planning I will say if you take a look at this it will give you some more information about what you're looking at. I don't think it will say there is the single best tool but you'll have a much better appreciation for what's the current state of the art in planning tools for distribution.

MR. PINNEY: For the co-ops pretty much all of them use windmill and then engineers develop their own planning methods on top of that. For the very well-funded utilities co-ops they like to buy CYMDIST, it's now an Eden product, CYMDIST, sometimes pronounced CYMDIST.

The trick will all of these is, well, DERs weren't around when these tools were built so you just can't click solar panel battery and autonomously control voltage regulator onto these models. So, then you can go to the research tools out there, open DSS and GridLAB-D(tm) and these are great. You can model all kinds of crazy things in GridLAB-D(tm). The trick there is do you have the IT and software guys who can go in and build it for you. The co-ops and NRECA in our work have been throwing off a lot of open source tools to make these advanced models usable. There are huge data conversion issues, data cleaning issues, which Jeff talked about.

And then there is the question of, well, what do you really want to measure once you can simulate all these distribution scenarios? That, I think, is somewhat of a solve problem for solar; it's rapidly being solved for energy storage. But when you look at the combination of these things together you start seeing some load shapes and some behavior that are very, very foreign to distribution engineers and I think that's an area of open research.

MS. SILVERSTEIN: Once upon a time, a long, long time ago I worked for Pacific Gas and Electric and more recently I have worked pretty closely with Hawaii Electric on renewables integration and energy efficiency and demand response and how we promote grid reliability and I have also integrated all of those with reliability. I've worked with a variety of advanced distribution projects and customer technology-enabling tools. My observation is that utilities have no freaking idea what's behind the meter. Things with the customers are changing far more quickly than most of the engineers with all their simulation tools will ever be able to imagine or put out there.

So, I think that one of the things we should be doing for grid planning is two things. One of them is detailed load research which is kind of old fashioned but it's always useful to know what your customers are actually doing out there and actually using rather than hypothesizing, using tools and assumptions that are based on five or ten-year old load research instead of looking at what's actually flying off the shelves in Best Buy and Home Depot.

Second, rather than just doing simulations we should be doing big data analysis, and instead of hypothesizing that I can model what I think is out there we should be letting the data tell us what's out there on the grid. We should also be developing a lot more stuff that you connect to the grid that is self-announcing or self-registering so that the mystery is removed, and that instead of me having to run big data analysis to figure out what's behind the meter we should have LEDs that give me a hint or whatever else is going on without going all the way into the whole privacy intrusions involved around a lot of the smart home kind of stuff.

Last is the great concern about all the modeling and simulation stuff that's going on which is the proliferation of electronically coupled devices and electronically controlled end-use devices that are not behaving anything like what most of the grid models and load models are based on, so that when you can buy all these LEDs and all these electric vehicles with all these PV inverters and all of the highly efficient but variable speed motors which are controlled by electronic drives, none of which have been programed to be friendly to the grid and to operate in the way that we have planned the entire bulk power system to behave, the possibilities of going into unstudied space because of something that happens at the transmission or distribution level. Again, the models for how load is going to behave are no longer to my mind at all credible. So, my hackles go up every time someone says I can just model that, it's handled. I don't think so.

MR. PINNEY: Just very quickly. I agree with that. I help distribution co-ops work on their models and getting the hundreds of thousands of variables in a distribution model correct is very hard. But we're also at a very exciting time where there's a lot of high-resolution meters, AMI SynchroPhasor out there, there's a lot of great load desegregation and load detection algorithms out there that work. With a little more bandwidth, if we can get this data back in a place where we can learn on it, I think we're very close to having very good circuit models from the meter all the way up to the generator.

MS. SILVERSTEIN: Segueing, John, to your question about what should the EAC be doing, one of the most valuable things to my mind that you all could be doing is laying down some markers for the importance of collecting and sharing data for the purposes of doing research and understanding things like load behavior, understanding things like being able to do big data analysis on PMUs. There's a lot of really silly reasons why entities are not sharing data today and those need to be knocked down.

CHAIRMAN ADAMS: Since you've done my segue I'll hit you with my question privately. I think I'm going to open to the group. We've heard the presentation, and we've heard presentations like this before. Now, what are we going to do, what should we do? Mladen?

MR. KEZUNOVIC: I'm new to the Committee so I guess I can talk from the top of my head here. The first impression here, we heard two extremely good reports -- I call this report, okay, this combined panel and resiliency report -- and they are the heart of maintaining service to the industry customers and so on. They are at the heart. Resiliency is at the heart, future generation of measurement technology is at the heart of doing that.

So, the question is how do we link the two? How do we link the two? In other words, what technology -- because there are variations here of things you can do in transmission distribution's customer side -- how do we match those? And the other thing is what else needs to happen to match all of this?

So, for example, if you are an investor on utility you are operating under FERC and MERC stuff like that -- we talked about that briefly, Paul. If I have PRC002, just picking up one, okay, how does this all fit -- I don't know if everybody is familiar with PRC002 but it talks about disturbance in coding and so on for the purpose of being able to monitor the dynamics of the grid and the performance of the grid. So, how all this ties together, for example, in PRC002. And I can go down a whole list of these things. If I'm not under jurisdiction of FERC and MERC, if I'm a muni or whatever, co-op or something like that, how does that fit there? So, that's one aspect of the link.

The other aspect of the link is -- I think I also mentioned a few times and I think it needs to be emphasized, the history of 135 years of running the power system is you do the measurements and you have the model and you make comparisons and things like that to control the system. With the high-resolution measurements like this we are gaining an enormous amount of data so we can develop data-based models. So, what is the role of data-based models in addition to the physical models to link back to the resiliency, to improve the resiliency? So, I think that's one of the fundamental questions.

Then the third one is how do we motivate all the stakeholders including the industry to actually put the products out there?

Those are the three things that somehow come -- as I said, this is my first experience but I was facing two really good topics and how do we link them together?

CHAIRMAN ADAMS: Chris?

MR. SHELTON: I would like to add to that I think it was mentioned in Alison's presentation about the introduction of machine learning capability and I think it just follows on this comment. It gives us the opportunity to have a better sensory motor-type model for the system and a new type of model that we couldn't otherwise create. So, when you combine this level of data and granularity, if it's synchronized, then you can build neural based and other models where you can actually have a much better self-awareness within the model to produce planning outcomes but also dispatch and control outcomes that we might not have otherwise anticipated with traditional approaches and the state of the art ten years ago.

CHAIRMAN ADAMS: Laney, thank you.

MS. BROWN: Actually, I was going to ask a question back to the panel because I think I started to say here's what she would do if she ruled the world. And I'm just curious, to the panel, what are the elements that you would consider in terms of areas of need or barriers that are preventing the ability to move forward?

MS. SILVERSTEIN: How wide an answer do you want?

MS. BROWN: How much time do we have?

(Laughter)

CHAIRMAN ADAMS: Fifteen minutes.

MS. SILVERSTEIN: No, I don't know what the scope of --

MS. BROWN: I think actually when I think about it, the nearer term. So, what are some of the elements, some of the things you talk about? Data integrity, as an example, or interoperability. I'm just paraphrasing. But I think there are some longer term ones. I think we tend to operate in a longer term one. Some of the things Jeff had mentioned in terms of this migration from existing legacy to new. I guess those are the types of things I guess I'm thinking about as we try to address what we may study, et cetera. I just wanted to get your thoughts.

MR. TAFT: For distribution there are a

couple of technical gaps. One I mentioned is knowing the connectivity models for distribution. At the distribution level the documentation that we have the databases are not always very up to date, but to make things worse unlike transmission the topology of distribution frequently changes on both short and long timescales.

So, here's an example. I did some work years ago for CenterPoint Energy and they're in the Houston area and they are a wireless company. They said, look, on a quiet day with nothing special happening we might do a hundred circuit switchings on our system; a hundred different topological changes, not the whole system but pieces of it. I was doing a project for them in which we needed to know that. So, they had a system that kept track of all that, an electronics system. And they said here's a file you can read. Every time there is a switching there's an entry made in this file so you can read this log file and you can see all the changes.

So, we start to read the log file and we noticed that some of the entries had two different times for a particular switching action. I said why are there two? They said, well, a lot of our switches are manually operated. A field crew goes out and the reason there are two times because the first time is when they called in to tell us they had switched, the second time is when they said they had done the switching a while ago because they don't always report it right away. So, then you're left with which one do I actually use, and by the way, one of them is what the field person recollected about how long ago they did it.

On the long timescale when you have a situation like we have in Florida now you know what's going to happen is they're reconnecting things, and the field crew are going to connect to the easiest phase to reach on the distribution circuit, all those things are going to migrate over to the closest phase to the truck and that's going to result in tremendous unbalance. And, oh, by the way, they aren't going to record all that either.

So, then there's going to be somewhere down the road, you'll see utilities do this like once a decade, they'll go and they'll fix all that. They'll rebalance everything and reconnect and put stuff back and they might document all of that. And then as soon as they do, or if they document everything when they're rolling out meters, right away that database starts to degrade again; it's got this half-life effect where it starts to go bad again.

So, if we're going to be able to do things at that level it would be nice if we had a way to continuously upgrade our model of connectivities so that we would know. We don't really have a great way to do that. From a technology standpoint there's kind of a gap. Another kind of a gap is how can we install sensing very cheaply? I mean, the installation process I mentioned, it can just be overwhelming to go out and install stuff even if it was free.

Next, looking at sensing and communications as an infrastructure layer has implications for how it gets financed. We could use some shifting of thought perhaps. We're starting to see that, by the way. In Hawaii they just recently put out a guidance -- well, recently at the beginning of the year -- put out a guidance about thinking about sensing communications as an infrastructure layer, and we've heard that from a couple of other utilities. But thinking about that more broadly is something that is probably a problem.

And as I mentioned, it's a heavy lift for utilities to do this. Distribution utilities a lot of times, like I said, they don't have distribution SCADA or it's minimal, they may not have substation SCADA or it's minimal. They may have geographic issues because of their service territories. So, getting there is a heavy lift and a slow process for them to get to the point where they have that kind of observability that we're talking about. It's a tough transition for them. The first step of getting the communications in place is a big one. It's like watch out for that first step.

MS. SILVERSTEIN: I'm going to segue to interoperability and resiliency and offer you a really practical example for your consideration of why recovering from a major storm or flood or hurricane is anti- interoperability. We learned this at PG&E after all kinds of disasters, they've learned it in New Orleans. And people sort of rarely acknowledge it but when you have -- the mutual assistance program is a fabulous thing. You get trucks and crews from all over the country and every single one of them has stocked up on nuts and bolts and equipment and they all bring their own stuff and their own methods and none of them match.

But if you're the customer, you're the utility, you're desperate to get everybody back up as fast as you can, as many as you can. And then later on five years from now or two years from now they're going to discover that the bolts that the guys from Detroit put up don't match the equipment that's on the truck that the guys from FPL or JEA are trying to unscrew and fix, and the jumpers are slightly different lengths and they're wound in a different direction. They're going to be a thousand different small things that make it harder and more expensive to fix and that are done -- thank God they're being done competently and well and quickly but it makes it harder and longer for the people who are long-term having to make all of those repairs work.

So, coming back and retrofitting all of that stuff, if FPL or JEA or Duke have spent a long time trying to bring in common equipment and common methods and high class, everything is standardized, having a disaster like this undoes the last five years' worth of planning and installation and upgrades. So, it's good short-term for the customer but bad long-term.

One of the things, if you want to link all of this to resiliency and interoperability, is you should think about the value potentially of standardization. Those of you who know that I worked at FERC in 2001 through 2004 might think that I'm a fool to talk about standardization again, but when it is something as basic as equipment, nuts and bolts, and some basic procedures every utility developed the standards that they did for really good legacy reasons, like it was cheap and it was easy and that's the way we've always done it. But maybe we should be looking at developing more common practices and moving forward some basic common equipment goals or practices might be a good idea.

MR. PINNEY: In terms of barriers, getting the most value out of the sensor networks, I think there are five big ones starting with interop. So, obviously hardware interop is an issue. Software interop is also a large issue. I've spent many months in windowless rooms writing software to move from one circuit format to another. I would not wish that on anybody. It would be nice if there were an accepted interoperability standard for that.

When crews show up after a disaster and they are not just handling hardware, they're also handling software and being able to interface with tools in an easy way is something that I know the most advanced software vendors are interested in, but that's still a challenge.

MS. SILVERSTEIN: But at least we've got geolocation standardized to some degree.

MR. PINNEY: That's true.

MS. SILVERSTEIN: Because it was worse ten years ago before GPS was widespread.

MR. PINNEY: Oh, I definitely agree. Map foot conversions have caused me quite a bit of pain, and I know are a difficulty in mutual aid situations.

Other barriers, bandwidth. It would just be nice to get all this data off meters. Another barrier which Jeff talked about, data integrity. I think there are a lot of opportunities to learn on these data sets and clean those things up. Currently the process is always manual. Cybersecurity, trusted tools and processes for securing the data on these sensor networks, which people are working at very quickly. And finally, applications to make use of these sensor data. The applications are not fully there yet but I think it's something that if the other barriers can be addressed the utilities and the engineers and the operators will write the applications. NIC co-ops writing machine learning applications already and playing around with their meter data. If they could get more of their data and make sure it's secure I imagine the applications would just come out of the woodwork.

CHAIRMAN ADAMS: Tom?

MR. WEAVER: The discussion around the PMUs and SynchroPhasors on transmission, it's clear that that is much more mature than what we have on distribution. Our sensors on distribution are very far from being mature.

I'll talk first about the cost and the application. Jeff mentioned the cost of going out and hanging a sensor. That's actually the easy part. It's the applications that David mentioned that's the hard part. You've got to get that data and you've got to do something with it, turning it into something that is meaningful. And most of these systems out there right now you have to pay the sensor vendor to host the system and then they send you the information after it's processed. We currently are working with our SCADA vendor to get some of these things built into the SCADA system but it's still a long, drawn-out process.

We know how to take sensor data and manually use it to locate a fault within five span lengths. We can do that, but we can't do it automatically. So, to me the harder part is automating the processing from the sensors. A lot of that's been done for the PMU applications, we just haven't been able to do that as much on distribution.

I also wanted to mention when you were talking about planning we got into the models and the accuracy of the mapping system, and that's certainly an issue, and the fact that it changes. But there are some more basic things. When I think about planning I think about the long-range planning of what capacities am I going to need on my substations and circuits in the next ten years. And there's a couple of fundamental things that we really need that we don't have. With all the DER that's out there we don't know what the DER is doing. And even if we put sensors on the line we still wouldn't know what the DER is doing if it's net-metered.

We just talked about this at EPRI earlier this week, and one of the things we really need is we need metering information from the production of those distributed generators. That way a planning engineer can look at his actual load recorded and say, well, I recorded 9 megawatts on that circuit, but at the same time I had 2 megawatts of generation coming into the circuit, so if that generation wasn't there I would need to provide 11 megawatts. We need to be able to make those forecasts and we can't do that.

So, as a practicing planner that's one of the things I think we need the most. Now, yes, we need sensors and at some point we're going to need PMUs because we're going to become a low-voltage transmission system and we will need that. But I think there are some more basic things that would help us in the short-term.

MS. SILVERSTEIN: I recognize that those are concerns but I would like to suggest with all respect that many of those technology capabilities exist, they just don't exist in the hands of utilities. And you, yourselves, at AEP have recently I think signed a contract with a third party vendor that can figure out nine-tenths of what you want and sell it back to you as sensors and data analysis and control of all of that stuff. The problem is that you don't own it.

MR. WEAVER: I just think it speaks to the complexity of going from hanging a sensor to actually getting information. A lot of people will say they can do a lot of things but to sign a contract one day and have information real soon after that is the difference.

MS. SILVERSTEIN: Part of the issue is also that utilities are used to getting information in only one way. I hang a sensor, I collect the information, I process it, I conclude what it means. One of the things that we did at HECO was we cut a deal with the PV installers to start feeding us the data on what all of the PV that they had installed per feeder was producing. And we also did a bunch of insolation-to-production analysis and forecasting that turned out very precise. So, between the combination of getting the PV vendor information, plus this analytical information from the forecasts, plus some monitoring at the feeder level, HECO is today about to do a very nice job of figuring out what it is they are getting in terms of PV production in near real-time.

But the other thing that you are doing is you are, I think, assuming that the customer is stupid and has no ability to control their uses. And in point of fact, one of the things that we could be doing is doing significantly more encouragement of automation and control capability by the customer inside her premises with her equipment so that the customer is no longer a one-way consumer and only consumer or a combination consumer and producer, but we are producing premises that are able to manage and integrate load and production behind the meter to deliver a relatively significantly more steady and less volatile a load demand that is drawing upon the system.

So, we can do a lot in terms of having the customers' PV, for instance, feathered, of having the load serve itself as a battery -- the building as a battery. There are a whole lot of things we can do with loads and customer- owned generation and resources that make them much more of a partner and much less of a burden in terms of what you need to do to manage the grid. But you all keep trying to take all of those responsibilities to yourselves and only to yourselves instead of working to facilitate that partnership.

CHAIRMAN ADAMS: Well, we're not talking about different business models than utilities currently have --

MS. SILVERSTEIN: Technology models too.

CHAIRMAN ADAMS: Technology models as well. And I know some of us feel like we're kind of tied down by the existing structure surrounding us which may or may not be so. But it does leave the question on the table for our Members, and maybe we can think about this during dinner, is what do we want to do with the information we gathered from these presentations? Do we want to do anything or do we want to say, ah, that's interesting, that was good stuff, I'll know something more in the future?

I thank you all for participating. I thought it was excellent presentation, very good panel. I got overwhelmed by the amount of information at so many different timeframes. I mean, from 60 samples a second to 5 bits per second is a pretty amazing range of data collection. So, thank you very much for your presentations. A big thank you to all of you. Thank you very much. (Applause)

I'd like to invite any final comments of the day from our Membership. Wow. I think we're all tired and ready to go to dinner. We have got a reservation at Pinzimini at the Westin Hotel for dinner. It is a (inaudible) affair. DOE still hasn't been persuaded to buy us all dinner. If there are no objections I'd like to stand in recess. We have consensus. Let's go to dinner. Thank you. (Applause)

(Whereupon, at 5:47 p.m., the PROCEEDINGS were adjourned.)

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CERTIFICATE OF NOTARY PUBLIC

COMMONWEALTH OF VIRGINIA

I, Carleton J. Anderson, III, notary public in and for the Commonwealth of Virginia, do hereby certify that the forgoing PROCEEDING was duly recorded and thereafter reduced to print under my direction; that the witnesses were sworn to tell the truth under penalty of perjury; that said transcript is a true record of the testimony given by witnesses; that I am neither counsel for, related to, nor employed by any of the parties to the action in which this proceeding was called; and, furthermore, that I am not a relative or employee of any attorney or counsel employed by the parties hereto, nor financially or otherwise interested in the outcome of this action.

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