EFFICIENCY COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	)	
	)	Docket No.
2008 Rulemaking on Load Management Standards	)	08-DR-01
	)	
Implementation of Public Resources Code 25403.5	)	
	)	

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

MONDAY, MARCH 3, 2008

10:04 A.M.

Reported by:
Peter Petty
Contract No. 150-07-001

COMMISSIONERS PRESENT

Jackalyne Pfannenstiel, Presiding Member

Arthur Rosenfeld, Associate Member

Jeffrey D. Byron

Karen Douglas

STAFF and CONSULTANTS PRESENT

Al Alvarado

David Hungerford

Jonathan Blees

Michael Gravely

ALSO PRESENT

Rochelle Chong, Commissioner
California Public Utilities Commission

Steve Berberich
California Independent System Operator

John D. Goodin
California Independent System Operator

Ahmad Faruqui
The Brattle Group

Richard Schomberg
Electricitie de France

Bruce Kaneshiro
California Public Utilities Commission

Jana Corey
Pacific Gas and Electric Company

Lawrence Oliva
Southern California Edison Company

ALSO PRESENT

Ted Reguly
San Diego Gas and Electric Company

Mark Gaines
Sempra

Jim Parks
Sacramento Municipal Utility District

Mary Ann Piette
Lawrence Berkeley National Laboratory

Tim Simon
Golden Power Manufacturing, Ltd.

Charles Toca
VRB Power Systems
US&R Power Group Partners

Helmut Blum
European Rolling Shutters
Blum Construction Co., Inc.

Rick Counihan
EnerNOC, Inc.

Rick Boland
e-Radio USA, Inc.

Gregory Tropsa
ICE Energy

Mike Heinrich
Electric Power Research Institute

Gayatri Schilberg
JBS Energy, Inc.
on behalf of The Utility Reform Network

Barbara R. Barkovich
Barkovich & Yap, Inc.
California Large Energy Consumers Association

Jane Turnbull
League of Women Voters

ALSO PRESENT

Klaus Schiess
KSEngineers, Inc.

Ben Metha (via teleconference)
Energy Connect

Richard Howburson (via teleconference)

Jim Arsenalake (phonetic) (via teleconference)
Peaking Power

Samantha Orney
Honeywell

Paul Angelopulo
Division of Ratepayer Advocates
California Public Utilities Commission

I N D E X

I N D E X

I N D E X

P R O C E E D I N G S

10:04 a.m.

PRESIDING MEMBER PFANNENSTIEL: It's really wonderful to see this many people here. This is a workshop, an Energy Commission workshop on load management standards. It's actually under the auspices of the Energy Commission's Efficiency Committee, but given the interest, and I think importance, of this subject we're joined today by two of the other Commissioners, and I think Commissioner Boyd will probably join us in the course of the day.

But let me go across the dais and introduce, for those who are not normal participants in our proceedings, those of us up here at the dais.

I'm Jackie Pfannenstiel; I'm the Chair of the California Energy Commission. To the far right is Commissioner Douglas; and to her left is Commissioner Byron. To my left is Commissioner Rosenfeld, who is the other member of the Efficiency Committee.

To his left we're joined by Commissioner Chong from the PUC. And I think most of you know that she has been the real leader in demand

response and energy efficiency matters in this area at the PUC. And we've been partners with her, and I'm delighted that she can join us today.

And then to her left is Steve Berberich from the California Independent System Operator. And his presence here shows that this is a big opportunity for the Independent System Operator, as well as the PUC and the Energy Commission.

We have a long full fulsome day. I'll just make a couple comments, a couple observations as we begin. This is the first of what I believe will be several workshops on load management standards.

This we've characterized as a scoping workshop. In other words, let's sort of get the lay of the land; let's see what's going on. And I fully expect and intend that we will have further workshops on specifically defined issues within the whole context of load management.

We have a long ways to go in terms of taking all of the work that's been going on for years, and where we are right now. We're right at the cusp of, I think, really making an enormous difference based on very good work at the PUC and a lot of effort there. And the technology

developments, as well as I think a large agreement within the state that the time is now.

I would offer that there are really four pieces to load management or demand response, however you want to call it. And several of them are in place.

I think one is the need for the meters, the smart meters. And those, thanks to the PUC, are starting to go in across the state; such that all utility customers, certainly of the investor-owned utilities, will have these smart meters in place in the near term. In the next several years they'll be going in.

The second is the tariffs to go with the meters. With the appropriate price signals customers can make the choices that we would like them to make on a demand response basis. They'll know when power is cheaper or more expensive, and when there's some emergency that would want them to reduce. But that will be a matter of tariffs, getting the proper price signals out there.

The third is whatever enabling technologies the customers choose to have to help them take advantage of the price signals. And those technologies are being developed as we

speak. And I'm hoping we'll hear about some of them today and perhaps more later.

The fourth part is one that I would argue we've sort of under-focused on, and we need to do more on, and that's customer information. There's a lot of both technology and technique that would be possible right now, but I would argue that most customers, and not just residential customers, I think a lot of the smaller commercial customers, don't have any idea of things they could be doing that they would never think to do.

I think we need to educate, inform, market, if you will, this stuff out into the general public so that when we start rolling out tariffs and when enabling technologies become available at Home Depot, people understand why they would be doing that.

So, today is going to touch on all four of those. But, as I said, I think that our point today is to sort of get the lay of the land on what's happening on right now and prepare ourselves to move more deeply into each of these.

I don't know exactly when the load management standard proceeding will come to a

conclusion at the Energy Commission, but I would expect that within this year, within this calendar year, we're going to have really put in place how these different pieces come together. And it may not be the end of the story, but it will certainly be the beginning of it.

With that, Commissioner Rosenfeld, do you have any comments?

ASSOCIATE MEMBER ROSENFELD: No, I think you said it well. Good morning.

MR. WELCH: Commissioner Chong?

COMMISSIONER CHONG: Good morning. I wanted to thank the CEC Commissioners for graciously inviting me to participate in today's workshop. And I'm also pleased to see representatives of the California ISO here, too.

Obviously the PUC and the CEC, the Cal-ISO have been working very closely together and very effectively on our demand response issues during the past several years. And I look forward to continuing to work with my colleagues.

And I wanted to extend a particular welcome to the new Commissioner, Commissioner Karen Douglas, who I met for the first time a few minutes ago.

There is going to be a very detailed presentation from the California PUC's Bruce Kaneshiro -- I see him in the back there -- a little later.

And so I wanted to just highlight a few things from my perspective, starting with dynamic pricing. A very important element of the Energy Action Plan is to make dynamic pricing available to all customers. And we've been hard at work at the PUC trying to make this a reality.

Last week the PUC approved a new rate design for San Diego Gas and Electric. The decision approved default critical peak pricing for SDG&E's largest commercial and industrial customers.

So SDG&E's largest customers will have a new opportunity to lower their bills by reducing usage during critical peak periods. This, of course, will make the system more efficient; it will improve reliability; and it will reduce greenhouse gas emissions.

The decision also begins to implement dynamic pricing for the residential and small commercial customers by offering these customers a peak-time rebate once they've received the new

advanced meters.

However, more progress does need to be made. For example, we need to move small commercial customers in the direction of time-of-use rates and critical peak pricing.

As we've seen in the wireless consumer world, consumers are quite capable of understanding prices that change during different times of the day, and making usage decisions accordingly.

So I do think that mom and pop businesses, residential customers will try to manage their energy usage if they think they can save money. So I plan to work with my colleagues to address this issue further.

We're also working on establishing dynamic pricing for PG&E's customers. One of our goals is to identify exactly what type of rates PG&E should offer to each of its customer groups, and to establish a timetable for the implementation of these rates.

The proceeding is also establishing rate design principles to guide the development of these dynamic pricing rates.

The other two investor-owned utilities

have been active in this proceeding, also, because we intend to take a similar approach for all the major utilities. We expect a decision in the proceeding around mid-2008.

We need to aggressively expand demand response in the state, especially because the demographic trends are working against us. California's annual electricity use per capita has remained relatively flat, thanks in part to the state's very aggressive energy efficiency initiatives.

On the other hand, peak demand per capita has been growing. The CEC forecasts that during the next ten years peak demand will grow at 1.35 percent per year, while the state's population will only grow 1.2 percent per year.

The trend is driven by population growth in the hottest areas of the state such as the Central Valley and the Inland Empire, where air conditioning is a necessity.

So you can see that we're very busy at the PUC on many fronts. We've been frankly pushing the utilities to be more aggressive in their demand response programs. And I'm pleased to see that the CEC is focusing on demand response

in this proceeding today.

During today's workshop I'll be very interested to hear particularly on how technology can enable more demand response. This is an area of great personal interest to me.

The CEC's building and appliance standards have been major drivers of energy efficiency. And likewise, there may be opportunities for more CEC standards that can push new demand technologies into the marketplace. And I'm very interested in us exploring them together to see what we can do.

For example, the utilities have been looking into how their new advanced metering systems can work with inhome technologies, such as smart appliances and programmable communicating thermostats.

The idea is it will make it easier for consumers to respond to changes in energy prices and critical conditions. Perhaps CEC standards could have a role in standardizing some of these new technologies in a way that will lower costs and increase their use.

Again, thank you for inviting me to participate today. I look forward to all the

presentations.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Commissioner Chong. Mr. Berberich.

MR. BERBERICH: Thank you, Chairman Pfannenstiel and Commissioners. I'm delighted to be here today. The California ISO is very interested in this topic.

We believe at the California ISO that the market, that demand should be able to participate on equal footing in the market, and that it can be a product that's on 24-by-7. And that it can participate in all elements of the market.

We also think it's a critical attribute to integrating renewables into the system. And we'll work to do that, as well. We think that's an important constituency in the state, and we think demand response can help with that integration immensely.

We also, at the California ISO, look forward to having the information available. It's important to us to know what's there and to know when it's gone, as well, so that we can manage the system.

And then finally, we look forward to

being able to access demand other than just in a stage two event. Right now the only way we can really get to it now is in an emergency event. We think we probably ought to find another way to go about that.

So, again, we're delighted to be here. We thank you for having us today.

PRESIDING MEMBER PFANNENSTIEL: Thank you for being here. Other Commissioners? Commissioner Byron.

COMMISSIONER BYRON: I'd like to extend my welcome to Mr. Berberich and Commissioner Chong. Thank you for being here.

PRESIDING MEMBER PFANNENSTIEL: Commissioner Douglas.

Well, with that, the agenda looks fairly detailed for the morning at least. But I do want to stress that there's going to be plenty of time in the afternoon for public comment and feedback. And we really want to hear about those issues that we haven't specifically pulled out for presentation in the agenda.

I know that there are people in the room who have products to sell, and this isn't exactly an opportunity for a sales pitch. But it is an

opportunity to let us know what's out there. So, you know, at the appropriate time I'm going to encourage that.

So, with that, let me turn to Mr. Hungerford.

MR. HUNGERFORD: Thank you, Commissioners. I'm David Hungerford; I'm the Energy Commission's Staff Lead.

PRESIDING MEMBER PFANNENSTIEL: David, would you see if your mike is on, and you may need to speak --

MR. HUNGERFORD: It is; I always stand too far from it.

Hi, I'm David Hungerford; I'm the Energy Commission Staff Lead for demand response. And will attempt to host this workshop today.

A couple of housekeeping things to begin. For those of you unfamiliar with the building the restrooms are off the hallway just outside this room on the other side of the glass behind you.

There are two exits in case of an emergency. One to the left of the restrooms on the south side of the building. That is alarmed. And the one you probably came in here at the front

of the building.

In case of an emergency or an alarm, please follow staff out of the building, and convene over at the park across the street.

As Commissioner Pfannenstiel pointed out, we have a very tight agenda today, so we're going to try to keep the presentations moving on time. And we want to reserve the public comments for the end of the day. Clarifying questions during the presentations are acceptable, but please try to restrict them to that kind of clarification.

There are people listening and participating by Webcast. And so if you do speak, or ask a question, we ask that you come to the microphone at the middle of the room so that people online and on the phone can hear you, as well. And the phones will be opened periodically to ask if anyone has a question who is participating by phone.

We'll be breaking for lunch around 12:30, if we can keep to our agenda. And we'll start promptly at 1:30 in order to complete the day and leave enough time for public comments.

And I ask you all to please mute or turn

off your cellphones so that they don't interfere with this proceeding.

So, thank you very much.

Let's go to sort of an overview. All right. Just a brief background. This proceeding was started through --

PRESIDING MEMBER PFANNENSTIEL: Can you dim the lights on the screen, please.

MR. HUNGERFORD: Yes. All right. The Commission approved an order instituting investigation, and order instituting rulemaking on the 2nd of January of this year that uses the Energy Commission's statutory load management authority to conduct these proceedings and create load management standards.

The docket number for reference is 08-DR-01; and you can find information on that docket on the Energy Commission website.

The general purposes are to assess rates, tariffs, equipment and software and other protocols and other measures that would be most effective in achieving demand response and to adopt regulations and take other appropriate actions to achieve a responsive electricity market.

The purpose of the load management standards proceeding is to obtain public input, explore the potential for peak load reduction and load shifting strategies, and explore coordination of regulatory authority and demand response efforts.

The purpose of this workshop today, to go back over a little bit what Commissioner Pfannenstiel mentioned, is to obtain background on the potential use of the Energy Commission's load management authority; to obtain public input on the topics the load management standards process should address; and to obtain public input on the load management standards process and schedule.

It's not to discuss the details of any particular topic or standard or technology, but rather to determine the scope of subsequent workshops. We'll cover those issues in detail.

This is just a visual of how the process will probably work, where we have the scoping workshop, the Energy Commission will produce a report that lays out how things are to be dealt with in subsequent workshops.

And then there will be workshops on a set of different tracks. The fact that there are

three here is not to say that we're going to have as many as three different tracks, or as few as three different tracks. That'll be determined in the workshop report. But just to illustrate that there will be a series of workshops on different tracks so that people's time is spent in the area that they feel that their interests are more useful and their input can be most useful.

And then finally, that will tie up to the adoption of load management standards.

And here is the basics of today's agenda. We have just had our 10:15 load management standards overview. And at 10:30 we're moving to our demand response overview, five minutes early, which I'm sort of proud of that. Good.

All right, let's move on to Jonathan Blees, who is Assistant Chief Counsel for the Energy Commission. And he's going to talk to us for a little while about the details of what the Energy Commission's load management standards authority is. Jonathan.

MR. BLEES: Thank you, David. Chairman Pfannenstiel, CEC Commissioners, Commissioner Chong, guests, thank you. Can you hear me in the

back?

(Negative responses.)

MR. BLEES: Okay. I will try to speak more loudly. If I fade, wave, jump up and down, yell and scream.

Ordinarily this presentation would be made by one of my legal colleagues, Bill Staack, S-t-a-a-c-k; you should be sure to address all of your legal questions, and especially legal complaints, to him.

(Laughter.)

MR. BLEES: Fortunately, or unfortunately, he was engaged in a bit of load management, himself. during the past week he was doing some offpeak skiing; it was offpeak at least in California time because Mr. Staack was in Switzerland. But he's back now, and he'll be taking over most of the -- at least the hard labor on this proceeding from me.

What I'm going to do today is go over, almost on a sentence-by-sentence basis, the primary statute that gives the Energy Commission authority, in fact a duty, to adopt load management standards.

I also want to point out, however, it's

important to realize that the Energy Commission's authority to adopt building standards which apply to all new construction in the state, and our authority to adopt appliance efficiency standards, which apply to the retail sale of appliances in the state, can also be important tools in adopting a comprehensive load management scheme.

The OIR that David just described to you did call out the building standards and appliance standards authority, as well as the load management statute. I believe that copies of all three statutes were appended to the OIR. I've also made copies available of those statutes today.

With that, if there are no preliminary questions or comments, let's proceed to section 25403.5 of the Public Resources Code, which establishes the Energy Commission's authority, and as I said, duty, to adopt load management standards.

As you can see, the first sentence of the statute says that the Commission shall adopt standards for a program of load management for each utility service area. This means not only the investor-owned utilities, which are directly

regulated by the Public Utilities Commission, but also the municipal publicly owned utilities such as SMUD, LADWP and smaller utilities throughout the state.

You should also notice that the statute commands that the standards be adopted by regulation, which means that the Energy Commission must adhere to the requirements of the state's Administrative Procedure Act in adopting the load management standards.

For those of you who aren't familiar with the Administrative Procedure Act, basically what it requires is that all state agencies provide reasonable notice of the regulations that they are proposing to adopt. That they provide explanatory documents, explaining and backing up the rationales and analyses for their proposed regulations. This includes, but is certainly not limited to a fiscal and economic analysis and environmental analysis.

The APA also requires state agencies to provide public opportunity for comment. The agencies must provide at least an initial 45-day period of comment. And if, as a result of comments received during that period, the agency

decides to change its proposal before adoption, it then must provide a period of at least 15 days for additional public comment.

The statute goes on to require the Commission to consider certain specified load management techniques, which we'll get to in the next couple of slides. I think the most important part about this sentence, however, is that it says that the Commission need not be limited to the techniques that are specifically called out in the statute.

As we'll see, that list of techniques that must be considered is, in itself, quite broad. But the addition of the need-not-be-limited-to phrase in this sentence makes quite clear that the Commission's authority is, in fact, very broad; and the Commission has the discretion to choose among a very wide variety of programs, techniques, systems, mechanisms and so on, in order to advance its load management and demand reduction goals.

The first technique that the Commission must consider in adopting any load management standards is changes in rates, adjustments in rate structure, to use the statutory language.

Obviously this is something that is well on the way with the CPUC's work.

This, again we see the broad, virtually all-encompassing nature of the statute here. Changes in rates can be either to encourage use of electricity at offpeak hours, or to encourage control of the load, so the changes in rates, new types of rates, new types of rate structures can focus either on shaving the peak or bringing up the use in the offpeak periods.

Changes in rates are the one type of load management standard for which the Energy Commission does not have exclusive or independent authority in order to implement the program.

As we see here, the second sentence up on the slide says: Any changes in rate structure are subject to the approval of the CPUC" through their ordinary ratesetting process.

Since the time that this statute was enacted, which was actually very shortly after the Energy Commission was formed in the late '70s, the Commission has interpreted this second sentence to encompass not only CPUC approval for rate changes for the investor-owned utilities, but also any changes in rates, rate structures, tariffs and so

on for the municipally owned utilities.

That is, if the Energy Commission wants to have SMUD adopt a new rate to encourage offpeak electricity use, the SMUD Board must approve that before it goes into effect.

The next two techniques that statute specifically calls out for the Energy Commission to consider our storage systems, the generation of electricity during offpeak periods and its storage, so that it can be used during the peak.

And the third technique is mechanical and automatic devices and systems for the control of daily and seasonal peak loads. Once again we see the broad scope of the statute.

Mechanical and automatic devices and systems for controlling daily or seasonal loads covers just about everything imaginable. Going back again to the need-not-be-limited phrase, earlier in the statute, though, we must recognize that the Commission is not limited to even this very broad statement of mechanical and automatic devices and systems.

Passive systems such as passive solar techniques, cool roofs, and so on could conceivably be part of the load management

standards adopted by the Commission.

Okay, so we've now seen what types of standards the Legislature wanted the Commission to be sure to consider. And we've also seen that the Legislature has given the Commission ample discretion and flexibility to look beyond those.

The Legislature has also established in the statute the substantive criteria that the Commission must apply to any load management standard before it is adopted.

Those of you who are familiar with the Commission's building standards and appliance standards will find some familiar words here. Basically the Commission must find that any load management standard is both cost effective and technologically feasible.

Here the Legislature has given a little bit more direction as to what cost effective means. It means that a standard must be cost effective when compared with the costs of new electrical generating capacity.

A question that may arise in this proceeding is whether those costs should be looked at from the point of view of the utility as a whole, or from the point of view of its customers,

if there is, indeed, a difference. Can simply point out that as long as there is evidence in the record demonstrating that the one choice or another is a reasonable choice, that the courts will uphold the Commission's determination in this regard.

Now, since these are utility programs, utilities are going to end up spending money. And the Legislature wanted to make very sure that utilities would not be harmed through the Commission's adoption of these standards.

So not only do the standards have to cost effective, but the Legislature has directed that any money the utilities are required to spend by virtue of a load management standard or any capital investment that they are required to make must be allowed by the PUC -- or again, we can also read municipal utility board here -- must be allowed by the appropriate rate-setting board as respectively either an allowable expense to be covered in rates, or an investment that must be rolled into, included in the utilities' ratebase on which, at least for the investor-owned utilities, they are entitled to recover, in rates, a reasonable profit.

Finally, the Legislature recognized that circumstances, whether they be climatic, type of customers, and utilities service area, types of buildings and so on, utility financial wherewithal and so on, that there are a lot of variations between utilities in the state.

And the Legislature wanted to make sure that at least in the more unusual or extreme cases that utilities would not be -- any particular utility would not be unduly burdened by a standard that the Commission was adopting for the whole state.

And therefore the Legislature created this clause which allows the Energy Commission to grant to a utility either a delay in implementing any one or more standards, or an exemption entirely. And you can see up there the various criteria that the Commission uses in assessing whether a delay or an exemption is appropriate.

Just want to, in closing, remind you again that it's not only this statute, 25403.5, which is important to keep in mind and to be guided by during the course of this proceeding, but also to remember that the Commission's building standards and appliance standards

authority may be part of the useful overall package, as well.

Are there any questions or comments?

PRESIDING MEMBER PFANNENSTIEL: Thank you, Jonathan. Questions from the dais? No. Thank you so much.

Moving on --

ASSOCIATE MEMBER ROSENFELD: Jackie, I think I would like to make one remark. It's not a question of Jonathan. It's thanking a lot of staff. Jonathan, you didn't mention that actually this is the second in -- proceedings. Way back in 2002, I think, right after the crisis, we had an OIR to do demand response jointly with the PUC, identical OIRs.

We set up working groups, one of which was chaired by President Peevey; and working group two, which was chaired by Mike Messenger. That was for large customers. Working group three, which was chaired by Dave Hungerford. (inaudible) we've been working very effectively as a joint staff for about five years.

And I just particularly want to thank David Hungerford and Mike Messenger, who's not here with us anymore, for lots and lots of time

invested in this -- great pleasure collaborating with the PUC.

That's all I have to remark. Thank you, Jonathan.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Jonathan. David, do you want to introduce the next speakers.

MR. HUNGERFORD: The next speaker is John Goodin from the California ISO. And he will be followed by Ahmad Faruqui of The Brattle Group. And by Richard Schomberg from Electricitie de France.

MR. GOODIN: Good morning. Hopefully this presentation goes a little better than my morning began. I actually started off in a blue suit as I was about to run out the door. Now I'm in a black suit. Somehow I set my suit jacket on the kitchen chair, I went in the laundry room and in that few moments I came out and my son had dumped his entire bowl of cereal on my --

(Laughter.)

MR. GOODIN: -- blue suit jacket, and was frantically, with a look of "don't kill me, dad", trying to make it all disappear off my jacket. So, it's been an interesting morning.

Well, first let me just say thank you to the Commission for the opportunity to be part of this process and to share some of ISO's perspective on these important subjects of load management; and in particular, demand response.

A couple of weeks ago I was at a scarcity pricing workshop, another fun topic, and was talking to a gentleman from the CPUC. And he shared with me a paper that he sort of harkens back to, and it was written by Dr. Larry Ruff back in 2002, on the economic principles of demand response.

And Dr. Ruff, as I read through that paper, he posits this question and draws this analogy. He says, so, what's more important in shaping metal, the hammer or the anvil. And I think as he agrees, and we would all agree, that they are both important, mutually important, and not one more than the other. And for the function that they perform it's really key is the interaction between the two.

And so what Dr. Ruff proceeds to do is extend that analogy to supply and demand. And when it comes to determining prices and quantities in the wholesale electricity markets, it's again

that interaction between supply and demand that matters. Again, not one more than the other.

And so I think that supply and demand, like the hammer and anvil, really do have unique characteristics and function. And, as such, I think that we, as policymakers, decisionmakers and then the regulatory processes like this one, that we really need to work towards insuring that California has three things really. The markets, the systems and the rules that can incorporate the unique characteristics of supply and demand; and enable them to interact efficiently and effectively through the markets for the benefit of the consumer.

Saying that, what I would like to do is just focus the part of my presentation on the markets. And believe it or not, many of us have been around this long, but the ISO is about to celebrate its tenth anniversary. We opened up our window, accepted the first bids and schedules back on March 31st of 1998, which is hard to believe it's been that long.

We've seen a lot of changes in that time. The market has evolved. And the ISO, as many of you are aware, is about to embark on

another significant step in its maturation process. Putting in a new market design called MRTU. Which is our market redesign and technology upgrade project.

And under MRTU the ISO, among other things, operates similar to today, a day-ahead and real-time energy and ancillary services market. And the core market functions that are part of MRTU are as follows. I just wanted to briefly touch on these.

Again, a day-ahead market and a real-time will be available under MRTU. And the day-ahead, obviously we open up the window, if you will, on a day-ahead at 10:00 in the morning. We clear bid-and-supply against bid-and-demand. We insure that all the flows and the schedules that are clear don't cause congestion. And so we insure that they have a feasible dispatch.

We procure the operating reserves and insure that we have that additional capacity available and sort of in-waiting, if you will, available if we do get into some kind of a condition in real time.

And finally, we perform a unit commitment process to insure that we have adequate

resources that can actually meet the ISO's forecasted demand and our reserve requirements.

So that's, in a nutshell, what the ISO does, among many other things in the day ahead. And in real time, when we actually get to that operating day, and that operating hour, the ISO core is doing that dispatch of the system, balancing supply and demand, and insuring that we can meet that instantaneous demand second by second. And also insuring that we are complying with WECC and NERC operating criteria, managing path flows, path limits, things like that.

So, again, in the day-ahead and real-time, those are some of the core market functions that the ISO performs.

And so it's largely through these market functions that the ISO tries to address day-to-day liability issues and concerns. As we know, we face a number of reliability challenges today, and others that are on the horizon.

And there are really three specific challenges that I want to illustrate this morning that I think demand, resources and load management strategies are going to play a significant role in their solution and in resolving these issues.

And those three are how do we continue to meet California's growing demand. Two is how do we increase load factor and slow the growth of peak demands, not just the peak demand, but peak demands. And third, how do we integrate and firm intermittent resources like wind generation.

And so let me start off and just share few slides around these key challenges. Number one, meeting the growing demand. Some of you have seen this slide. I've shared it before in other presentations. And this is the ISO's load duration curve from September of '05 through September of '06. And remember on July 24th of '06 we had our all-time system peak of 50,085 megawatts.

What I want you to capture in this slide is really the information that's in the middle of this slide. The system was over 45,000 megawatts. In other words, between 45,000 and 50,000 megawatts only 57 hours, .65 percent of the time.

So 57 hours out of 8760 hours the system was over 45,000 megawatts. In other words, we, in California here, had to carry 5000 megawatts of capacity and insure that that was available so we could meet this peak.

And likewise, the system was only over 40,000, a difference of 10,000 megawatts, between 40 and 50, only 279 hours, or 3.2 percent.

So, again, as the system peak continues to grow, there's anecdotal evidence that the system is actually growing more peaky, that, you know, can we continue to build our way out of this. Or do we have the ability to look at the other side of the equation, the demand side, the demand resources to help address this issue.

Second key challenge is increasing load factor. I have a slide in here for summer and winter. Because reliability challenges aren't just a summer issue.

Again, looking at that July 24th, we looked at the system peak at 50,085. Notice what the system was doing on the offpeak. It was at 28,424 megawatts. That's a difference of 21,000, almost 22,000 megawatts that the ISO had to ramp up and pull back, ramp up during this heat storm. That's an incredible amount of capacity you have to have sitting available at minimum load in these offpeak hours, so you can ramp it up in the onpeak.

Wouldn't it be nice if somehow we could

not only shave this peak, but also shift some of this peak and increase load factor.

Let me give you another example of increase in load factor, even in the winter. These are two dates here in February. February 5th and 6th. And what you'll note is this is a very typical load profile. This is a 24-hour strip of what the load was. Very typical for this time of year.

You'll notice we start off the morning, you know, very low. We ramp up steeply to about 10:00, 11:00, noon. We had this first peak, then the load starts to taper off. Then you notice, boom, we hit another very steep load increase at guess what, around 5:00. There's a coincidence with office load and residential load hitting here; street lights are turning on. It's an incredible amount of load that hits the system so late.

And we have to be able to maintain and meet this peak. And in fact, Jim Detmers, our VP of operation, says he has to actually keep on some large thermal units just to be able to dispatch those units for those four hours; back them off; have them sit at minimum load for all other 20

hours; back them up at the four hours; back them off; and so there's tremendous costs, inefficiencies and some environmental impacts, as well.

So, that is another key challenge. It would be nice to shave some of that peak and shift some of that peak.

And finally, this third challenge of integrating intermittent resources, this is a great slide that shows back in April of 2005 the Tehachapi windfarm and what the output was at that windfarm for different days in April. You can see it's very challenging to try to predict any kind of output and forecast the wind.

And the point here is this, is that again we harken back to July 24th. You can see that during that heat storm in July, these are what the generation installed capacity was for the wind generation and what it was actually doing during this heat storm.

But let me show you the coincidence of what the wind output was during the peak hour. And those are the red dots. So we have 2658 megawatts of installed wind capacity, but you can see what it was actually doing during the peak

hours. It wasn't contributing much because there really is an inverse relationship between wind and heat. The reason it's so hot is because the wind's not blowing. So.

(Laughter.)

MR. GOODIN: Okay. Now, one thing that the ISO does want to stress, it's very important to us, is that -- these slides illustrate it -- is that demand resources, load management strategies must be available more than just summer peak days weekdays, for example, as many of the programs are currently constructed.

We have reliability challenges and needs all year long. The ISO dispatches the system every day, second-by-second. We really need demand resources and load management strategies that can contribute every day.

In fact, Steve has called our lab DR-365, demand response 365 days a year. We need to figure out how to get to that point.

Okay, let me shift gears quickly to the working groups. Again, we're going to be beginning MRTU in about some time this year. The ISO, in conjunction with the CEC, the CPUC, utilities, third parties, other aggregators, have

assembled five demand response working groups where we're working to help shape the future model and integration of demand response resources under MRTU.

These five working groups are as follows. These five working groups are led by the three different agencies, PUC, CEC and the ISO. And really they sort of encapsulate many of the different aspects of trying to sort of pull the whole piece together and the whole puzzle.

And as part of the working group process this third line down, DR participation in MRTU release 1A, the ISO is leading this effort. And the ISO is actually proposing market design enhancements to allow demand resources to fully function with the flexibility that we provide supply side currently in our market.

We're going to put in design enhancements to allow demand resources do the same. To have that full flexibility, functionality and integration into our market. And that's going to occur one year after the startup of MRTU.

Which leads us to this issue of integration. Why is integration of responsive

demand so important. Again, it's the hammer and that anvil effect that we talked about earlier. Without that integration or what we call the interaction of demand at the wholesale level inefficiencies result.

And that is if demand responds outside of the market, or if the ISO has no knowledge of that demand response occurring, which is largely the case today, then ISO will clear the electricity markets and commit the resources necessary to maintain reliability without regard to the contribution that demand resources provide to the market and our operations.

And this leads to obviously inefficient market outcomes and the potential for double procurement of resources.

And so what I want to do now is just quickly walk through a simple example where today close to 80 percent of the demand response that we have in California is only available in an emergency. About 1700 megawatts, that's a significant resource, only available in emergencies.

And as such, the ISO unfortunately cannot plan around or even consider these

resources in our daily operations.

And so let me illustrate this point, is that if we have 1700 megawatts of demand response that is emergency triggered, let's say our demand forecast is 45,000 megawatts on a particular day. And the day-ahead forward energy market clears 43,000. In other words bid and supply clears against bid and demand of 43

The ISO knows our forecast is 45, so we will commit an additional 2000 megawatts of resources to be available in real time.

What you don't see here is that the ISO did not commit only 300 megawatts, in other words the 45,000 minus the 1700, which is 43,300; the ISO, when it goes into its day-ahead process must plan to meet all of the load, including the nonfirm load that is associated with interruptible programs, and may be available to you if there is an emergency declared.

And so we don't plan the system to be in emergency state so that we can have access to these emergency-triggered programs.

So the challenges today is that state policy currently counts emergency-triggered resources as being part of the planning reserve

margin, if you will, that resource adequacy capacity. And that is the capacity that's made available to the ISO to plan and operate the system day to day.

And so there's really a disconnect here between sort of the resource that we have for planning reserve versus the type of resources that are actually presented to us.

And so going forward the ISO really wants to coordinate efforts with the CEC, the CPUC and stakeholders to continue to insure that future retail programs and tariffs integrate into the wholesale markets and provide the resources when and where they are needed.

And so retail demand response programs should be able to convert and translate, as this slide demonstrates. And my last slide into wholesale market products as this. All retail programs, again, should be able to translate, transition, convert into wholesale products.

The wholesale markets are fairly straightforward, again day-ahead and real-time. We have day-ahead energy and ancillary services markets. We have real-time energy and ancillary services market. Products need to be able to fit

into these categories.

And so in closing, again, I touched on early about markets, systems and rules. In conclusion, I would just encourage the Commission to continue to support and help accomplish the vision of integrating demand response in the wholesale electricity markets and grid operations so we can see and experience the benefits of these resources.

And have better coordination around DR programs, particularly those that account for resource adequacy capacity. And insure that again these programs can convert into products that are used by and useful to the grid operator all the way into real time.

The second was systems. Encourage the CEC to take a lead through the demand response working group process and through this proceeding. Again, to help fit the technology and infrastructure pieces together to connect end users where the resource resides to the ISO where the actual market outcomes are produced and reliability is maintained.

And finally, on rules, the ISO encourages the CEC to work collaboratively with

the CPUC in bridging the disconnect between retail tariffs and wholesale electricity markets.

And hand-in-hand, I think a very laudable goal would be o focus a great deal of effort on educating consumers about the time varying value of energy and how consumers can respond to manage their costs.

And I really believe that we need to get to a place to where consumers understand load management and demand response like they understand energy efficiency today.

So, with that I'll close. Thank you for this opportunity. And we appreciate being part of the process.

PRESIDING MEMBER PFANNENSTIEL: Thank you, John. Are there questions?

ASSOCIATE MEMBER ROSENFELD: I guess I'd put in my usual comment. I've already praised collaboration between the CEC and the PUC. And we had demand response meetings on Thursdays and John, when he comes in on lightrail faithfully, and the collaboration's been great. And thank you, John.

MR. GOODIN: Thank you.

MR. HUNGERFORD: All right. Mr. Goodin

has done a pretty decent job, I think, of laying out some of the problems we face and some of the challenges --

ASSOCIATE MEMBER ROSENFELD: David, louder; closer to the mike.

MR. HUNGERFORD: -- we're going to be working with in this proceeding.

I'd like to move on now to some presenters who are going to give us a perspective on what is being done in other places.

Dr. Ahmad Faruqui of The Brattle Group worked with the Energy Commission on our Integrated Energy Policy Report process last year and developed a couple of reports that are available online that talk about what the Energy Commission's possibilities are for load management. And basically laid the groundwork for this proceeding.

He's going to give us some background on what's being done in other places in the United States.

And following him, Richard Schomberg of Electricitie de France will -- not a great pronunciation, but I tried -- will be following to give an international perspective.

Dr. Faruqui.

DR. FARUQUI: Thank you. It's a pleasure to be here as a followup to the earlier discussions that David just alluded to. And what I will provide briefly is, you could say, 30,000-foot overview on what's happening around the rest of the United States.

But in so doing I found it useful to also include California in that comparison. Some of the maps and charts will not exclude California, they will include California, as well.

As we look at the map of the United States what we find is the DR is, indeed, widely deployed across the country. But there's a big catch. And the catch is it is mostly triggered during emergencies. And I believe that was also, to some extent, what we were hearing from John right here in California.

This map is a DOE map. It is the best I could find in a quick search. It is a bit dated, and I have already been informed by people sitting next to me and people who I emailed this to over the weekend that their state is not fully captured. And they do both DR and energy efficiency, or they just do this or that. So look

upon this as an impressionistic map. Just look at the colors at a high level.

And what we have is the blue color has shadings. Just ignore the shadings because they have to do with natural gas programs.

So just think of this map as having either blue, which is both EE and DR; or having just green, which is EE. And then there are a couple of states that just have DR. And it looks like there are at least two states that seem to have no action going on.

Again, this map might be a little bit dated, so just look upon this as an overview. FERC has indicated in its survey that 234 utilities offer DR programs around the country. And this DOE study says that there are some type of DR in 42 of the 50 states.

I'll now move on to NERC. The information from NERC, as you know, is presented by the NERC reliability regions or councils, as they're called. And here is their snapshot. So this is for the year 2007. This is from their summer assessment.

And what you see is the percentage of total load, which they call it total demand, that

is being met by demand response. And it has ERCOT on the very left; and it has the Western Coordinating Council on the very right. And then on the extreme right is, of course, the United States as a whole. The numbers you're looking at for the U.S., as a whole, are between 2 and 3 percent.

In addition, the colors indicate that the load control programs, which are shown at the top with the dark orange or rust color, are present, and most significantly in the State of Florida. And I think several of you are familiar with that. No surprise there.

Let's turn to some FERC data. And in particular, the data I'm showing you is for the RTOs, ISOs around the country where there are organized markets. And what I have decided to focus on in this chart is the share of demand response that's coming from the emergency programs versus the economic programs.

And as you will see once again, the emergency programs dominate except in PJM where there is almost -- well, there's an even balance between the economic and the emergency programs in PJM.

These programs are not just the programs being offered by the RTOs and the ISOs. They also include the programs being offered by the load-serving entities. So, this is a composite chart that's showing the combined effect in the marketplace, or DR, regardless of who is doing it.

But as you can see, the message is that by and large there's a very heavy dependence on the emergency kind of programs, and not enough being done on the price-responsive or the economic kind of programs.

And those, just to follow a point that John was making, the 45,000 megawatt number, that's the demand forecast to begin with, well, these economic programs can reduce that number from 45,000, let's say, to some number that's below 45,000. I won't mention a specific number because it would send waves through the room, as my comments usually do. What I will do is just leave it at that. There's an opportunity to lower the peak demand number if you have the economic programs. If you don't, then there's less of an opportunity.

Now, if you look back at the heat storm of 2006, and we look at the various heat rates,

the percent of peak that was shaved off, it turns out that California dispatched the most demand response during the heat storm of 2006.

And that's, you know, a very interesting comment because, you know, we tend to see a lot of charts that show California as not doing a lot. But here we have an example of California actually doing a lot, doing more than anyone else did. So, that's worth noting.

Additional demand response comes from dynamic pricing programs aimed at customers greater than 500 kW. This is mostly happening outside of the United States in markets that are either restructured or in the southeast where there's a lot of active interest in real-time pricing.

And so you have the examples of Georgia Power, Duke Energy and Tennessee Valley Authority with their RTP programs. And, of course, in the restructured markets, the last bullet that I have, for example in Texas, New York, New England and PJM, you have hourly pricing being the default rate for all of those customers who are generally above 500 kW. In some cases it is as low as 300 kW in the mid-Atlantic region. In some cases it

is 600 kW. It depends on the metering capability.

I've talked to a number of those people and I've tried to figure out why it's --, and it's just because of the metering limitation, not for any other reason. They are defaulted onto hourly rates that if they don't like them they can move on to whatever other rates might be offered by the competitive retailers.

That does create a lot of DR. We have a very rough estimate here of 1 percent. That when you add all of that up, this is the price responsive DR in these markets. The customers above 500 kW, they're contributing about 1 percent. And when you add that to the reliability-triggered programs it adds up to about 3.5 percent of U.S. peak demand.

There is a recent study that I'm performing for EPRI and EEI, along with several other consultants. And in that study we are making a national projection of the impact of demand response. And if you look far out to the year 2030, the impact we are projecting is about 10 percent.

We are starting out at 3.5 percent. So, over that span of time we expect the 3.5 percent

has a significant probability of becoming 10 percent.

Now, obviously there are a lot of unknowns in this projection, and those will be spelled out in the report. But this is just a perspective on the future.

it has been mentioned by Commissioner Pfannenstiel and others that advanced metering is now spreading. And it's certainly a trend that we are observing nationwide. This is the number of utilities that are now moving with the deployment of AMI. You can see the number is picked up.

What that has led to, of course, is a lot of business cases being carried out; a lot of research being done through pilots on whether or not customers actually will respond to these prices.

And by and large, the evidence is overwhelming positive that when customers are given an opportunity to see those higher prices they see an opportunity to lower their bills by curtailing their peak usage and moving some of that usage to the offpeak periods.

The first set of bars I show you to the left of the vertical line, the hash-line, are

customers just on time-of-use rates. Two of them are coming from Ontario. Then we have the California pilot, the statewide pricing pilot. And then we have a pilot in New Jersey. Those are just simple time-of-use rates.

Now, I heard in the previous presentation a comment that DR-365 is what the Cal-ISO would like to have. And, in a sense, time-of-use rates are an example of something that his 365, because they're there every day.

Now there are pluses and minuses of having something that's there every day. The customers have to work harder every day, not just on the 15 critical peak days, let's say. There's more education, though, that occurs once they are being trained every day. And so that's the TOU snapshot.

To the right of the vertical line we have programs in which the time-of-use rate was coupled with an enabling technology like some kind of a programmable or smart thermostat. And what you see is, even though it's not one-on-one, I have slightly different utility on the right side of the vertical line from the ones on the left line, but at least for PSE&G, the utility in

Newark, New Jersey, it's the same utility. And you can see the technology does lose response. It's very clear, even with the time-of-use rate.

And then we have the California advanced demand response system, ADRS pilot, that shows significant response to those rates on the noncritical days when there was just a time-of-use rate. And you have Gulf Power.

Then we move on to dynamic pricing. This is the pricing option like critical peak pricing. It is only there on the really critical days. And on those days, again, you know, I realize that the bars are not going to be very legible, but just look at the general appearance and height of the bars for the next few minutes for those who don't have the handout.

And what you see is that the numbers that we have for the critical peak rates are higher. They are approaching upwards of 10 percent just about in every case. And in some cases, they're hitting 20 percent; in other cases they're hitting 45 percent. That's without enabling technology.

And then you go on to the bars on the right side, and those are with the enabling

technology. Generally, if you line them up side by side, you will see that enabling technology will boost responsiveness upward of 50 percent. In some cases it will double it, but in most cases it will raise it at least 50 percent.

In the center we have the peak time rebate, which didn't have enabling technology. And you can compare that with the results that we have, let's say, for the California statewide pricing pilot.

The opportunity cost that customers face with a rebate is the same as what they face with the critical peak rate. And while we can argue metaphysically whether it's the same or not, the empirical results that we have today indicate a strong encouraging similarity in the results.

Now, having said all of that, the big issue is we are still at 3.5 percent of which 1 percent is coming from the price responsive programs, most of which are the large customers. There is very little that's happening for the retail -- for the residential and small C&I customers who are, of course, the most numerous customers in the power markets.

So we step back and we look at what are

the barriers. Now, as you remember, we had two workshops last year on barriers in California. We talked to two dozen stakeholders.

So over the last couple of years I have traveled around the country. I have met commissioners from several other states, utilities at the NARUC meetings. And interestingly enough, there's a striking similarity between the California barriers and the national barriers. Even though California can claim to be very different in so many other respects, when it comes to barriers with DR you're still suffering.

So the United States is not quite a republic of demand response just yet. We are getting there, but slowly.

What are the barriers. The first barrier is there's still issues of coordination between the state and federal agencies that are responsible for demand response. And, of course, by that I do include the RTOs, ISOs, the state commissions and the utilities, ultimately.

That's being worked out. There have been several meetings at the NARUC conferences on this. Every Sunday morning at 9:00 there's a gathering. I think Jon Wellinghoff, Commissioner

Wellinghoff of FERC, referred to it as, you know, the Sunday church meeting of the DR goers.

Well, they are still working on it, but there's a lot still to be done. It's not clear what can be done, but there's a lot of conversation going on.

Second, there's a disconnect within the states and the regions between the retail and wholesale power markets. This is well known. It's one of those stubborn problems that needs more attention and more creativity or it will not budge. It's been at least five years, right, since this problem was recognized, and it's a hard one.

Third, there are retail rate freezes, not just in California with our own AB-1X, but there are freezes in Illinois and Maryland and Delaware. They're all beginning to come up. Not AB-1X, but all of the others. They're slowing beginning to come up.

And that's creating quite an opportunity for demand response. But until they are fully up, there's still this ambiguous state of what do we do. There are those long-term contracts that people have signed, not just in California but in

the province of Ontario.

I was before the Ontario Energy Board a couple of weeks ago and similar kind of discussion. And the Chairman of the Board, who used to be a federal judge, looked at me and he said, you have come very late. We have already signed those contracts. This game is over.

But there were other people who disagreed. So, there's a lively debate on what can be done. You have real resource costs. You have the load duration curve that we saw. But Ontario has also a very steep load duration curve. No amount of contracts will wish that away.

It's like the law of gravity, it's there. You can't just get in a weightless suit on earth and pretend to be weightless. It's still there. You have to deal with real resource costs.

Okay, then we have lack of advanced metering. There's still 14 or so utilities with advanced metering. Most of them have no dynamic pricing. You have a lack of enabling technology.

Now, a couple of weeks ago I was invited by a large company in Silicon Valley to talk to them about DR and enabling technology. I was really surprised how well informed they were.

This was not a utility; this was not a state commission; this was not an ISO.

This was a company whose eyes are on home automation. And they're seeing tremendous opportunities. So we talked a lot about the Gateway system. Costs $1500 today. Their projection is it might go down to $50 in just five years.

You know, that's the kind of transformation of the market that would really change the horizons of these enabling technologies.

There is, of course, customer fear of price volatility. In general there's a tremendous opportunity for customer education. The term load management and critical peak pricing, those terms can never be used in the presence of real customers. All of us are customers, but we are so used to these terms that they are second nature to us.

Customers get scared of terms that imply management; that imply some kind of control by a third party. We all know The New York Times article, I won't go there. So those are the issues that people are concerned about.

And then it comes to our program design. And having been, myself, a program designer, I'll be the first one to admit that there is room for improvement. There is a lot more that can be done to get customers interested and attracted to these programs. That's where a lot of marketing research and marketing, I think, can play a role.

In many markets aggregators are still not allowed. They have to work through the LSE. They cannot bid directly into the RTO market. And that hampers their efficiency and the amount of market opportunity that they can go after.

So those are the barriers we have heard about as we have talked to people around the country.

And this is my last slide. The big issue is I was asked by some to do a little scorecard, you know. So take this with a pinch of salt or a wink of the eye. And here is my scorecard.

As far as the ISO RTO based reliability triggered programs are concerned California appears to be on par with the rest of the country. As far as price responsive programs go, both retail and wholesale, California currently lags

the country. And there's one big reason for it. We don't have, at this point, a functioning wholesale market. I know it's coming. We don't have it yet. And all of those restructured states they have a real advantage. They've had that for a few years and that's why you have large numbers of customers on hourly pricing.

And then you have the interesting southeastern United States, Georgia and Duke and TVA, where they're not restructured, but they have really gone ahead and done a lot of real-time pricing. That's what's causing California to lag behind.

And I believe, as our metering programs accelerate, and as the market falls into place, a lot more things will happen. California will always outrun the other parties, history has shown. It's just a question of doing it in DR and the price-responsive DR, and doing it sooner, as people expect California to lead the country.

Third, dynamic pricing for large power customers, I already talked about that. That's covered in the previous bullet.

And as far as the mass market goes, by and large everybody acknowledges that California

has done the best pricing experiment in the country. This experiment is actually being used by people around the globe. We're not always sure credit is being given to California, but the numbers are being used. And I guess you just have to Google it and you'll find it.

It is moving faster than the nation in terms of AMI deployment. And I, personally, am quite optimistic that in three years California will really be ahead of the country in this space.

That's my two cents. Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Ahmad. On your last point about AMI deployment, are any other utilities moving where the California investor-owned utilities are going with AMI right now?

DR. FARUQUI: They are doing business cases. They are looking at what California is doing. I would say, by and large, they are doing experiments, and they're doing business cases.

I haven't seen anything, other than Ontario, which we know about, in Canada, they plunged ahead without doing a business case. Everybody else is in the throes of doing a business case.

There are about 100 business cases being done in the United States. Not all of them have demand response in them, but I would say an increasingly large number, because the gap is real.

I believe initially the gap, when they looked at PG&E's original filing, the gap was around 10 or 11 percent. When Edison's and San Diego's filing came in around 60 percent, 40 percent was the gap. And then PG&E's updates.

Everybody is now conscious of the fact that in order to cover the more enhanced AMI features there will be a gap. They will have to do DR. And they are not certain that their customers are ready for it, so they're doing pilots. You know, that's sort of where a lot of people are today.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Other questions?

ASSOCIATE MEMBER ROSENFELD: I have a comment. You praised the statewide pilot project. But I want to remind the audience that that was done like four years ago. But when it sounded like Gateways would really be expensive, we now think that communicating thermostats are going to

cost maybe $25 more than just a regular set-back thermostat.

And what we are planning on doing is to have demand response tariffs with underlying technology. And so I'm just repeating your words out there. We expect -- we should get results which are 50 percent or 100 percent better than what we got in the statewide pilot project.

DR. FARUQUI: I think that's a good comment. The other observation that some people have made is that in the statewide pricing pilot there were no inhome displays, because those were not commonplace at that time.

All of the more recent pilots are including those inhome displays and they might further boost response.

ASSOCIATE MEMBER ROSENFELD: Yes, and they'll teach people about how they use electricity. And that will help with everyday energy efficiency also.

DR. FARUQUI: Exactly, yes.

ASSOCIATE MEMBER ROSENFELD: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Other questions. Commissioner Chong.

COMMISSIONER CHONG: Good morning,

Ahmad. It's good to see you again.

You made a comment that one of the barriers is unimaginative program designs. And then another one was aggregators not being allowed into the market.

Has anyone been focusing on some best practices in terms of program design? Because I do agree with you that, you know, one of my issues with how the PUC currently does it is that maybe we're too passive in terms of program design.

Do you have any comments on that? Thank you.

DR. FARUQUI: What I would say is, you know, as we have talked -- and my comment was intended as a national observation as opposed to just the California observation.

Much of this is coming from the utilities, themselves, and from the state commissions. As far as best practices go for dynamic pricing and DR, there are very few that have done it well enough to be able to say this is the best practice.

What we have is best practices for direct load control programs, you know, which is, of course, an emergency kind of a program. There

are ways of getting customers on those programs. They are well researched.

But for pricing, dynamic pricing in particular, those practices, I would say, for the residential market are under-researched. There's not enough data. There is only good evidence on real-time pricing for the large customers, and that's what we have, for example, from Georgia Power. I would say that's certainly a best practice.

Where we can perhaps borrow some examples from, and again, it's a big perhaps, is in the energy efficiency space where we have had many years of history, both in California and elsewhere.

People have figured out how to market efficient air conditioners to customers. The question now is to market efficient pricing that goes with the efficient air conditioner. And that's where we have currently a gap.

I believe a recent report has been put out by ACEEE on best practices for energy efficiency programs. Again, not looking at dynamic pricing or demand response. There might be some analogies there that might be worth

looking into.

Or we may have to do more focus groups and more structured, you know, pilot programs to test these ideas. Maybe we don't need to test anymore where the customers respond to the rates. We already know that five times over.

But what we don't know is what attracts them to these rates and how to make the rates more interesting. That's where we have a gap in knowledge. I think that's where some research might be worth doing.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Ahmad.

DR. FARUQUI: Thank you.

MR. HUNGERFORD: Thank you, Ahmad. Now we're going to move over to --

ASSOCIATE MEMBER ROSENFELD: Closer to the mike --

(Laughter.)

MR. HUNGERFORD: I think it just sits down here; that's the problem.

Now we're going to move over to Richard Schomberg who will provide us with an international perspective. Thanks very much, Ahmad.

MR. SCHOMBERG: Thank you. Good morning and thank you for having me here. First of all, I am from the edf, Electricitie of Europe. The "f" should be changed, we're an "e" now, I think.

But I am also a member of the Gridwise Architectural Council of the USDOE. And President Elect of the Standard Committee Organization is IEC -- system aspects for energy.

The challenge here is within ten minutes give a flavor, an international flavor. So I'm going to actually really focus on maybe more Europe. And also, while they are things that are well known by a lot of people, so I will try to do a presentation to maybe highlight a few features that I think are not that well known.

Okay, so now if you're visiting a house in France, and I'm sorry because I'm going to use a lot of the slides. And I realize that most of you will have a real hard time to see the slides. So I will try to take that into account.

So, typically I will show here, let me put the punch line first, we've been doing 30 years of load control which is some kind of demand response at three different levels. And that's what I want to show with very simple technology.

And we have achieved a 10 percent peak reduction on an entire country the size of California. So, typically if you visit a house you will see meters. And so you have meters. Whether we still have some electromechanical meters, or solid state meters.

But there is something that you don't have here in this country, which is an automatic circuit breaker which is calibrated to a maximum amps amount. You know, France, and many countries in Europe, actually when you pay electricity you pay two things. There are two buckets. You pay a subscription fee that you would have to pay even if you don't draw any energy from the grid. So you pay a subscription, and you pay a consumption.

The subscription fee is how it's used to actually determine how much amps you're allowed maximum to draw from the grid. And, of course, the more you won't make energy reservations from the utility, the more you pay. It's absolutely not linear. So you really have interest to really stay the lowest reservation of power. And really have the lowest caliber here.

But, of course, what happens is that in the house when you start to pull more intensity,

or you have more appliances connected, then it triggers this box. And that's it. And you cannot override this box. There is no way.

The only way to do it is actually just to switch off appliances, or unplug appliances. And then try again. Okay.

So the people have been used to this now for 40 years. And it's part of the culture. And the people are okay with the fact that you cannot override this.

So, that's the first level. And then we have also something else in Europe, which is switch panels which are standardized. And that's really very interesting concept, because you can have fuses, circuit breakers, but you can have also very clever, very smart modules that can be added very very easily. And as it is standardized, it's a huge market. So I will come back to the standard idea later.

And, of course, you have this switch panel controls electric circuits. And, of course, the most important electric circuits in the house are electric heating and electric water heaters.

So, now when you have a lot of appliances in the house, and that you want to

subscribe to the lowest amps, then you very often get in trouble. And a lot of people have been implementing a second level of load control, direct load control, which is a box here that's even an electromechanical device that actually just prioritizes the appliances.

And you can override this box, but you always have to sacrifice something. Because you cannot override this one. So this one actually helps flattening the load within the house, okay.

Now, the third level we have been adding actually some communication between the meter and a relay that actually triggers the electric water heaters just at 10:00 p.m. at night, which allows actually a day/night tariff. And it is very simple, but it's been proven incredibly efficient. Because every night in France you have 10 million electric water heaters that are storing the electricity generated by 20 nuclear reactors, which is a third of the nuclear reactors we do have.

And that's very simple. And it's been working for 30 years. This system has been designed at the same time as we decided to build the nuclear fleet. It really goes with it. And

also it works even with electromechanical meters.

That's the result we got. You see those are actual load curves; from far in the distance you cannot read the figures, but it's interesting because from far you can see that it's quite flat. And this is really what we achieved with very simple technology. And it was one-way technology, very easy.

And sometimes the people don't have enough hot water because, of course, you heat the tank overnight and then you use the water during the day. So then you can always override during the day the water heater. But you cannot override the box that is limiting, that puts a cap on the amps.

Okay, as Chairman Pfannenstiel explained the four dimensions, I address the meter dimension.

Now, there is the rate dimension obviously, where I'm not going to go into great details. Nothing very original, but we have implemented, we have flat rates, we have peak hours. That's what I just described with peak and offpeak tariff.

And there is actually a 40 percent

difference between the flat rate. And actually what you pay during the offpeak of this peak rate.

There is the -- tariff that I will comment on the next slide. And we do have a critical peak pricing program, also, where 22 days we might have energy which is eight time more expensive. And it's always day-ahead alert on all those.

So, I want to focus and give some information about this tariff. This is an old story. I would say it's an old love story, because we have implemented this in 1993. That's 15 years ago.

And the idea was an all winners, no loser plan. And we do have actually a fleet of 400,000 customers. And the satisfaction has been always very high, over 90 percent actually. We have a lot of studies, a lot of data on behavior, on understanding of the people, on what they've been doing with this.

And I'm going to try to make a few comments using the slide here. So, what is this tempo tariff. It's actually a six-tiers tariff, which is we do have three colors, blue, white, red. That's the French flag. So that it was easy

for the people to remember.

You have three colors. You have 300 blue days, 43 white days, 22 red days. And for each day you have a peak and offpeak, night and day, basically, rate. So total six tiers.

And this graph that is difficult to see from the distance is the average power, the actual average power of those customers, are depending on the different types of days and peak and offpeak.

So here it's 2500 watts, actually. So average over all the customers, you can still see from the distance that we have had a real effect on the consumption.

And the studies have been showing that there's a potential of 7 million customers that would benefit from this tariff, that would really draw huge benefits from this tariff.

And if we get subscription of those 7 million customers, we could actually lower the load by 6 gigawatt in red days; about the same in white days, actually. Not that much difference. And we would actually raise the consumption by 2 gigawatt during the blue days.

Another interesting thing, this graphic that you cannot see is the distribution of

different appliances that the people are -- that they sacrifice first. You see when it's red or white. So definitely the tv set, they don't want to sacrifice this. Neither the microwave oven, maybe to have a pizza ready to watch tv. And also the hot water.

Very strange in the middle you have the vacuum cleaner, you see. Maybe too much crumbs on the ground, the pizza, I don't know.

(Laughter.)

MR. SCHOMBERG: I don't know what. But they would sacrifice, you know, all the laundry machines and even -- eve electric heating. Because, also, what I didn't say is that we've been targeting customers that might have several ways to heat the house. And it's really then being able to switch, really it's a huge behavior shift there.

So, now the last graph I want to comment is this one which actually shows how much time was needed with each customer to get the customers started. Because -- and I'm not sure it's well known, we have been spending a lot, a lot, a lot on actually advising prices before signing of the people. Going to the homes and really spend

literally an hour or half an hour in the best cases, to help people understand what it is about what they can do, answer all their question, getting them in confidence.

And we have also organized commercial followup after three month, after one year. And, of course, what happened is that the people give up this box, you see. All the people who signs up, they get a box where they have a day-ahead color of the coming day so they know in advance.

And 10 percent of the customers actually afforded to have an energy management system that is being doing the job for them. And then they been getting, they been reaping much much more benefits.

But 90 percent of satisfaction. The people -- we don't know anyone who actually has been paying more electricity -- got a bill higher with other rates -- than with the other rate.

We still have about 3 percent of people who, after the first season, winter season, wanted to just drop off the program. And it's despite the fact that they have been getting some savings. But they thought it was not enough savings. And there is a kind of threshold under which the

people don't want to bother. Even if they don't have much to do. The threshold is about $150 for the bill, the annual bill. And I guess that's all I wanted to highlight here in the tempo program.

So now today where do we stand. Now, everything is changing in Europe. The market is hundred percent open since last July, which means that everything we've been doing up to now has to be redesigned one way or the other. And we do have retail competition.

So, we've been undergoing everything a lot of utilities have been doing here in this country. And we are redesigning completely our advanced metering infrastructure, which somehow -- well, the functionalities are very much like everything we're doing here in California.

And also we are developing a lot that you cannot see far in the distance, but we are developing automation. And the first driver is really more energy efficiency than demand response.

By the way, this automation is embedding a lot of demand response. And that's very consistent with what Ahmad said about recent discussion he had with some technology providers,

who are looking, watching the market.

So, I'm showing here three, I would say, three subsidiary of edf, three parts of edf. One is our German company; one is the UK company; and one is edf in France. And we do have, adapted to the culture, programs that we are studying and developing.

And, of course, the big part of this is not much the technology, but as Ahmad said, we need to really find out what all the market drivers, how do you get people interested, excited.

And here is my last slide, and I want to share those conclusions with you. Definitely load management and demand response is becoming of international interest for I would say different drivers.

In Europe it's been more energy efficiency up to now. Here in this country you might have more pressure because you maybe cannot build power plant as easily as we can do. So you are maybe first in line, or you would prioritize demand response higher, which is, I would say, a good thing. Because you are moving the ball.

And the real challenge I see is the

business case. To actually have decided demand response deployment. Because in my company I still have a lot of people are not convinced that with out own situation, well, they're not sure if it would be better to build a nuclear power plant, or actually implement all this.

But I'm convinced that here there is no choice. And that's a perfect solution to the problem that this country and the state is trying to solve.

All the trials and return of experience that we have conducted, and I just shared something real that we have a lot of data, it's not that well published. But we have a lot of data showing that there is a huge consumer acceptance.

But we need actually to spend a lot of time with the consumers. And it's not just finding a new issue, or advertising an offer that is going to make it. And we realize that in our case we had to spend a lot of time with the consumers. Which also explains why we don't have more of those customers signed up. Because that's really the costly part in the offer I presented.

That now technology is allowing to do

things faster and deeper. And I'm sure it will be much more easier.

And definitely when the appliances were able to take care of what we can call the market transactions at large, then the people all have been very happy and have a huge savings.

And even the fact that in France the people cannot override several of the levels of the load control. Well, the people, they live with it, and that's perfect. And they understand why.

Definitely in Europe it's more homotomaceous solutions that are developed and that are promoted. But actually to me it is addressing exactly the same needs.

And I'm sure that, well, technology are widely available. And, in fact, they are. They are far too many. And the problem now that we all have to face is that it's very easy to find a very very cheap technology. And do deployment of a couple of million.

But now a key for the collective success, the key is to agree on some kind of standard. So that there is a market. Because it's easy for California, for a couple of million

devices, to get a good price. But then where is the market. For edf with 35 million customers, we can have custom devices developed. But where is the market. It's not enough.

And so it's very interesting to not just try to do the cheapest things, but things that are open enough so that a market can exist for the vendors. And so that everyone's going to benefit.

That's all the comments I wanted to make.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Richard. I'd like to pick up a little bit on your -- you observed that there's a difference in different cultures of the countries that edf serves. And you specifically talked about what you could do in Germany and what you could do in the UK, compared with what goes on in France.

And then from that you discussed involving consumers, spending more time with consumers. How do you find that? And do you find that you need to offer different programs or programs are accepted differently by different cultures?

MR. SCHOMBERG: That's a very interesting point, because, of course, as we are a

European company, we would like and we try to coordinate as much as we can, and even standardize within the edf group, what were are doing in the different counties.

But first, we have different regulations in different states. And you also have to take into account the legacy and what the people have been used to, and start from there.

So, this is where the offers have to be -- well, it has to be innovative; it can be disruptive, but the people will understand better if it comes from what they already accept to like.

Now, we have tried -- we have been working with larger and larger panels. And this is where we very quickly realized what was the difficulty even with six buckets prices, to have the people understanding.

And in a very simple way, because it dealt, in Europe, all Latin people are not that inclined to the market, market things. You see, they prefer comfort rather than looking at grabbing some little savings.

And it's interesting, this is where actually it's amazing to see how on the tempo experiment the people were really caught, and it

was amazing to see how well they understood how it works. And they started to develop even strategies, clever strategies to play from them.

ASSOCIATE MEMBER ROSENFELD: Richard, I'd like to follow up Commissioner Pfannenstiel's a little bit more.

You gave a very nice overview of how Europeans look at tempo. But you also understand the American scene pretty well. You live in San Francisco.

What was envisioned here was a little more -- that is we'd envisioned home automation networks which would be preprogrammed instead of your having to test to see whether you can be turned off.

So, we've envisioned a system with at least a PCT and probably, as soon as possible, control of the pool pump and spreading gradually to the whole house.

Is that the appropriate way to go? From an American point of view, is that the appropriate way to go.

MR. SCHOMBERG: I'm very honored that you ask me such a question. And by the way --

(Laughter.)

MR. SCHOMBERG: -- my father was American; my mother is French. So I'm allowed to say bad things on both sides.

(Laughter.)

MR. SCHOMBERG: But no, I have been pulling back a slide that is, I know you cannot see it, but it was to give a glimpse of things we are working on for Europe. Which is exactly what you described.

I mean I think you've been investing a lot to actually move the entire industry. I am monitoring a lot of AMI projects for different reasons. And because also I love those -- this topic.

And I have seen many people mimicking actually what has been done by some of the IOUs, California investor-owned utilities here. And you also, you're looking into -- I would characterize what you've been doing up to now, PCT or Gateway, you're looking on how to leverage at maximum the existing feasible technology, which is cheap enough and that actually does not -- well, it prepares the future.

I mean it's not because -- if it's cheap, it's easy to deploy. But it's also open

for anything else in the future. And this is what I like very much. Because you're really trying to -- you don't want just to push a cheap, feasible thing. That would be easy. You could have done it already for some time.

You're trying to harmonize the needs and get the ball rolling. And it's of interest, also, for our project at edf. But it's also of interest to me, as President Elect of the Standard Organization, where actually we have started to deal with this topic with 29 national committees.

And I have started actually to have adopted use case methodology that has been developed here in this country, and that has been used by SCE, if I can name them, in their AMI project. And this methodology has been published as an international reference within one year.

So I also -- I open the way to also be able to have international standards within one year and not three to five years.

ASSOCIATE MEMBER ROSENFELD: Thank you.

PRESIDING MEMBER PFANNENSTIEL: On the question of the enabling technologies, it's separate from the AMI, I know that you're also very involved in the evolution of those

technologies.

I think that I know we've had recent discussions about how things are happening right now. And Ahmad mentioned some work that he looked at in Silicon Valley which may or may not be the same work we've been looking at in Silicon Valley.

What's going on in Europe? Are you able to capture or observe these new technologies, the enabling technologies, and are they replacing some of what you would have thought of as the home network?

MR. SCHOMBERG: Yes. And I will try to be short because I could make a lot of presentation on technology. But, if I try to characture, in Europe the people are much more working on solutions through the existing wires. That people would call power line carriers, or with power line.

And in the U.S. the people are much more working on wireless solutions, talking about technology.

And that is fascinating because it doesn't mean we're not interested in wireless, but for some applications, we are following very closely what's going on here.

And I'm sure that the solution that's going to be deployed very shortly everywhere. So, I don't want to -- I'm very careful not to name any brand or whatever. I would have to think more about making a presentation, a fair presentation here.

But, I'm sure that we're going to see invading the world wireless technologies developed; and it's going to be started to be implemented here in California. Because there is all the state doing things, but I don't know any other state actually investing to actually give that extra push that's going to make it happen.

There are many technologies thriving. But the wireless technology will come from here.

For solutions through wires it's much more developed, much more on the radar screen in Europe. We are developing even more advanced power line carrier technology, you know, third generation, that will actually, will surprise a lot of people, I think.

And we do that -- well, there is a reason. It's not because one is better than the other. It's because when you have a transformer, as a utility, in the U.S. you have a couple of

houses by transformer. In Europe, you might have 100 to 400 houses by a transformer. So this simple fact is pushing the thinking in a bit different directions for economical reasons.

But at the end I would bet that some of the power line carrier technologies that we are pushing will find their way here. I'm not saying they are not here, but it's not the hot topic here. But it may become.

PRESIDING MEMBER PFANNENSTIEL: Thanks, Richard. Other questions? Yes, Commissioner Byron.

COMMISSIONER BYRON: Mr. Schomberg, I just wanted to thank you. It's great to have your perspective here. But, again, thank you for coming.

MR. SCHOMBERG: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Others? Yes.

MR. BERBERICH: Mr. Schomberg, thank you for coming today. I have a comment and then a question. I agree with both you and Ahmad, the technologies are quite readily available for this. And they are adapting to wireless networks here in the U.S. We actually had some demonstrations at

the ISO of how those work.

Though I note, I know in France most of the generation is nuclear, which obviously lends itself to a flat curve. And I'm curious, though, you talked about the hot water heaters, obviously, as a storage mechanism. And I'm wondering if you guys have adapted any other storage mechanisms to help flatten out that curve.

MR. SCHOMBERG: That's very interesting. Actually with nuclear we would dream to have a flat load curve. Actually we have a kind of flat generation curve.

But we -- and by the way, we have developed a unique technology allowing to do load following with nuclear power plants. Which means that we can turn the knob 50 percent to 100 percent, most of the countries it's 100 percent or zero.

So, now -- and this is why we had to develop other things along with nuclear and nuclear power fleet. What we've been developing, and it's not that well known, at the time we decided to implement, to start to build it, that nuclear fleet, we have developed some pumped hydro.

Okay, so in France we do have 80 percent nuclear generation. We do have 15 percent of hydro generation. So that's 95 percent non-CO2 emitting. Half of these 15 percent of hydro generation is pumped hydro. So this is actually one of the best storage that we have. And I guess the one that may compete with this in the compressed power storage. That we are, well, we are following what's going on on that, okay.

Did I answer the question here?

MR. BERBERICH: That's good, thank you.

MR. SCHOMBERG: Okay.

PRESIDING MEMBER PFANNENSTIEL: Any other questions? Thank you, Richard.

David, I think, since we are an hour behind, what I would like to suggest is that we break now for lunch. And so that we can start that panel of what else is going on in California immediately thereafter.

So, it's just about noon now. So, I would suggest that we be back here at 1:00. Any other -- yes, any comments?

MR. HUNGERFORD: Two things.

ASSOCIATE MEMBER ROSENFELD: I have a question. Is Joe Songsell (phonetic) in the

audience? I'd like to meet him at lunchtime if he's here.

MR. HUNGERFORD: Two quick things. You'll find that upstairs, up these stairs by the security guard's desk you can go there with your visitor badge without checking in any further. There's a small convenience store that has sandwiches and soup and that sort of thing, if you want to make a quick lunch.

Otherwise there should be a list of other near restaurants around here. And you'll have to move quickly to go to a restaurant and get back here by 1:00.

And so we look forward to seeing you afterwards. Also, if you're going to want to make any public comments, there are blue cards on the table out front to the left.

(Whereupon, at 12:00 noon, the workshop was adjourned, to reconvene at 1:00 p.m., this same day.)

--o0o--

AFTERNOON SESSION

1:07 p.m.

PRESIDING MEMBER PFANNENSTIEL: My suggestion is that we start with the presentations that were supposed to be done at the end of the morning. But we try to hold on schedule as much as we can going forward.

It is really important that we have time at the conclusion of today to hear from others who are here who haven't been put on the program to give formal presentations.

I have a number of blue cards from people who would like to speak. If you'd like to, I will, when we reach the public comment portion of the proceeding, I'll ask people who have filled out the cards. There will still be a chance for others.

But if you'd like to fill out a card I think they're out on the table, and then they can get brought up to me.

So, with that.

ASSOCIATE MEMBER ROSENFELD: Jackie, can I make a one-minute --

PRESIDING MEMBER PFANNENSTIEL: Yes.

ASSOCIATE MEMBER ROSENFELD: I wanted to make a comment, I hope I can make it in a minute, about PCTs. I read the utility presentations last night -- come on for advocating PCTs.

The thing is the PCT, as defined on our website, is not the PCT -- as defined on our website a month or so ago, is not quite what it is today.

When we first thought about PCTs it was mainly for the price response. And the idea was that even if you had preprogrammed a certain response to a price voluntarily, they could -- that particular afternoon might be not feeling good, or having -- to override. So there was an override button specified on the PCT.

The only place where it wasn't override-able was during emergencies, because the thought was by controlling the thermostat, you could avoid, greatly increase the probability of having rotating outage, which is a lot more catastrophic.

However, in early January Joseph Songsell (phonetic), a hard working engineer, looked at our website and discovered that there was this non-override-able characteristic for emergency events; and was very concerned and wrote

an article in "The American Thinker." And that provoked quite a storm which convinced us that there are a lot of people in California who are concerned with a utility being able to set up your thermostat during an emergency.

And so I want to remind people that the Energy Commission issued a press release saying that, henceforth when we think of a PCT, it's universally override-able, even during an emergency, even if you've made a -- unless you've made a contract with your utility on an individual basis.

And will be a universal override, but there will be no possibility that this is used in anything but a voluntary way.

So when we talk about PCTs for the next half an hour, I guess it is, we're thinking that either that these always have an override which applies all the time.

PRESIDING MEMBER PFANNENSTIEL: Well, since we raised the PCT question, I would like to make a couple comments, myself.

First is that, as Commissioner Rosenfeld said, PCTs, when they're in homes will be totally voluntary, override-able.

Second, we also said in that same press release that we would not consider PCTs as mandatory for the 2008 building standards. In other words, they were removed from consideration in the 2008 building standards. And that still remains the case.

The third thing I would say is that I see PCTs as a potentially valuable enabling technology. It is not, as we know, the only enabling technology out there. And it may not be the best for certain applications. It may be better for some applications than others.

And I'm not personally convinced that it is the best, most cost effective technology out there for all residential customers.

And that's largely what I would hope we can consider through this proceeding, by putting PCTs out on the table with other enabling technologies, potential enabling technologies. And trying to determine what makes the most sense for the load management objectives that we're setting out for ourselves.

And as I started today I talked about the four parts of this equation. And there are the meters are going in way before the enabling

technologies. I mean these, if they were in the '08 building standards, they would be being phased in over some subsequent number of years. Meanwhile the advanced meters are going in on an expedited basis for everybody.

But then there are also the rates, and we need to figure out, working with the PUC, what tariffs make the most sense.

There's also the customer information part. And I think what Commissioner Rosenfeld was describing was some lack on our part of informing customers of what's available, what's needed and how we take advantage of these things. So clearly we need to do that.

And then the enabling technologies, including PCTs, are a fourth part that we, I believe, need to do some more thinking about in terms of how they fit in with the others.

So I know that we will hear more about them, but I want it clear that I, for one, haven't decided how they should fit into the picture at this point. And so whether some parties here support them or oppose them or have some different perspectives on them, I think that's fine. But we're still at the questioning stage of that.

Any other leading questions, issues, discussions? Turn it back to Dave Hungerford.

MR. HUNGERFORD: All right. I hope that everyone can hear me. I was reminded a number of times during the break that I need to speak into the microphone.

We're going to move ahead today with the California Public Utilities Commission with an update on what they have been doing to effect demand response and the advanced metering infrastructure. And my colleague, Bruce Kaneshiro, will be giving that presentation.

ASSOCIATE MEMBER ROSENFELD: And you will dim the lights, David?

MR. HUNGERFORD: Right.

MR. KANESHIRO: Good afternoon, Commissioners. Thank you for the opportunity to present. As David said, I'm going to walk through a summary of the demand response proceedings that have been going on. Some of them have actually dated back to 2003 when we first started into demand response.

I've organized my presentation along the five major topics, overall demand response policy, some action items that were taken on recent

accomplishments, and then getting into something specific, such as advanced metering, ratecases and dynamic pricing, demand response programs, particularly enabling technologies, and integration with the ISO's MRTU. And then some tools that we're developing in terms of demand response, such as forecasting, measurement and evaluation.

I think everyone knows that first point that demand response has been and continues to be a high priority energy resource, second only to energy efficiency and the Energy Action Plan's loading order.

The Energy Action Plan 2008 update, which was, I think, released just last month, lists several key demand response action items going forward.

Obviously the first one is why we're here today. The second one addressing the constraint that we currently have with residential customers, the AB-1X problem, as we often refer to, constrains the ability of the PUC to add a time-variant dimension to residential customers' electricity rates.

Those last four bullet points we've

talked a lot about today already. Making more progress with dynamic pricing; the rollout of advanced metering and the tariffs that go with those, as well as automated DR. Modifying the retail DR programs so that they are better integrated and can more fully participate in the ISO's markets. Something that John Goodin presented early this morning. And then, as I said earlier, the protocols that we're developing; some tools by which we can evaluate our forecast of demand response load impact and then the cost effectiveness of the programs.

I thought I would just highlight real quickly what's been accomplished so far. And I think we all know many of these things already, so I'm just going to very quickly touch on it.

Advanced metering has gotten us underway for PG&E; it's going to start soon for San Diego. As Commissioner Chong summarized in her opening remarks this morning, default CPP has been adopted by the PUC as of last month for San Diego's large C&I customers. That same decision authorized the peak time rebate program for San Diego's residential customers.

The first phase of integrating the

retail DR programs with the ISO's operations has been complete. It's in place for this coming summer. And so the ISO now has the ability to be informed by the utilities as to what demand response programs they're planning to call on a day-ahead basis.

By having that information the ISO now is able to adjust how much resources it's going to be procuring with that information. So that's a really big first step for us, in that prior to that we did not have that type of integration between the regional programs and the ISO's operations.

The existing demand response programs. As I said before, those have been in place since 2004, 2005. As of today they offer a broad range of options for customers to participate in all together. When I refer to them I mean the emergency-triggered, as well as the price-responsive. They equate to over 2000 megawatts of DR potential capacity.

That last bullet point is just a highlight of the PUC's integration of demand response with our resource adequacy requirement in that DR currently qualifies as a resource in

meeting the load-serving entities' RER. That's really important for us to have established that, encouraging demand response.

Just some brief notes here about PG&E's AMI project. In 2006 the Commission authorized PG&E's full deployment AMI proposal. You can see there the number of meters for both electric and gas that are going to be deployed.

At that time the deployment schedule was going to take five years from '06 to 2011. And as of November '07, PG&E's installed about 243,000 meters, that's combined gas and electric. Mostly in Bakersfield and Sacramento.

What I did put up there on the slide is the rate that's going out with these meters. As the meters have been deployed and they're going to be marketed this coming summer, PG&E is offering a voluntary critical peak pricing program for these residential customers.

Now, in December of last year PG&E came to the Commission with a proposal requesting additional flex to upgrade the AMI system. And the highlights of its proposal are there. They would like to put in a solid state metering technology that would enable them to then, those

two bottom bullet points, remote connect/ disconnect; and home area network Gateway devices. So the ability to communicate to appliances within the home.

There is no schedule yet for this proceeding; it's just begun. But PG&E has requested a decision, I believe, October 2008.

For San Diego the Commission approved their full deployment AMI proposal last year. And there you see the numbers for the amount of meters they're doing. They're currently finalizing the contracts with the meter infrastructure vendors, and will be seeking approval of those shortly. And full deployment is expected to begin around '08 and finish by 2011.

Edison's proposal is currently under review at the Commission. And a schedule on their proposal is scheduled for August 2008. And if it's approved then, that time that you see the deployment is scheduled for Edison.

Dynamic pricing. The Commission is handling dynamic pricing mostly through the utilities' individual rate design proceedings, sometimes referred to them as general ratecases.

So, San Diego was the first to go

through the process. And as Commissioner Chong highlighted this morning those are the two, I guess, key takeaways from that decision with respect to demand response and default CPP rate for San Diego's larger customers.

Those sub-bullets under that are some, I guess, if you will, some protections for customers for this rate. Basically some opt-out opportunities for the customers, once they're placed on it.

The first one is a 45-day opt-out at the initial point of implementation. Then after a year has passed, the customer then has another opportunity to opt out of the CPP.

For those customers that stay on it for that first year there's bill protection. Meaning that the customer pays no higher than what they otherwise would have paid on their alternative rate. The idea there being to give the customer an opportunity to try this out without being hurt by the bill impacts.

Another option that customers have is this capacity reservation charge. You could think of it as a hedging premium where customers identify amount of capacity for the year. And if

they stay within that capacity their usage is not subject to the CPP rates when a CPP event is called. If their usage goes over that capacity amount, then that amount is subject to CPP rates.

The other main piece of that decision is the peak time rebate program for the residential customers. Essentially the customers receive an incentive for the amount of load they reduce below a specific baseline that's been established for them during a PTR event.

The customer's baseline is essentially their historical usage adjusted for temperature. And one, I guess, tweak that was made to the original proposal is that it's a two-tiered incentive structure where there's a higher incentive for the customers who install enabling technology.

For Edison their GRC application, I believe, is due in March 2008. And we expect them to include in that application as default CPP proposal, as well as a PTR proposal.

PG&E's dynamic pricing proceeding is also their general ratecase. And within this proceeding somewhat of a different approach, but as you can see there, that objective is to create

a year-by-year strategic plan for PG&E to develop their dynamic pricing rates.

The plan tries to answer those three questions. What types of dynamic pricing tariff should PG&E offer. When? And how should these tariffs be designed and integrated.

And so this proceeding took a step back from your typical general ratecase that we have at the Commission. It has gone through a series of workshops and rounds of comments trying to answer some questions about dynamic pricing tariff design. Should it be voluntary, should it be mandatory, should it be opt-out. What are the tradeoffs of rebates versus rate signals or pricing signals, What costs should be recovered to the time variant portion of the rate. What hedging options should be provided to customers, and so on.

So, it's been a process of developing a record, trying to answer these various specific design questions that come up when you're trying to come up with a dynamic pricing tariff.

This next slide shows where we are today. There was a ruling that was issued, Commissioner Chong's ruling, January 23rd, which

has a draft timetable for PG&E rate proposals. And that table was actually quite intricate, so I just tried to take the highlights of it for each of the classes in there.

If you look at the residential rates there's two different tracks it can go depending on what happens with AB-1X. If it remains in place, then the timetable anticipates that really default PTR, peak time rebate, is the option for those customers.

Or they could opt in to a time-of-use or CPP by 2010. That's presuming that they have the advanced meter at that time.

If AB-1X goes away or is ended or is somehow changed, then that changes things quite a bit. And residential customers are anticipated to be on a default time-of-use CPP rate with the option to opt out to time-of-use or flat rate. And this would happen a year after.

For the small and medium commercial/ industrial customers, default CPP is expected in 2010, with an opt-out to TOU. Again, that presumes that the customer, by 2010, has the advanced meter to participate. For the large customers time-of-use or real-time pricing is

anticipated by 2010. And by 2011 a default, real-time pricing option is considered there.

And real-time pricing is dependent largely on the implementation phase for MRTU; when there's a day-ahead market that'll be offered.

For small and medium agriculture that's default TOU. And I do have one error in this slide on that point for small ag. It's default TOU in 2010 with opt-out to CPP, not to TOU. And then for large ag it's again a choice of CPP or real-time pricing in 2011.

So, again, this is a draft, a draft of the timetable that's been developed over the course of the proceeding. I believe that comments by the parties have just come in on this draft. And as Commissioner Chong said, there's a decision, the next step in this process is a decision probably sometime in the middle of 2008.

Okay, real quickly, going to the demand response programs. The utilities are currently funded on a three-year cycle. And so the current cycle is 2006 to 2009. As I said earlier, there is a whole variety of triggers for these programs. Some are triggered on day-of, day-ahead basis. Some are emergency only.

You have a variety of extended structures for them. Some are capacity payments, energy or both. And today we also have different operators of these programs. Some are operated by the utility; some are operated by third-party aggregators in contracts with the utilities.

Enabling technologies are starting to play a larger role in demand response. One of the programs that has been recently approved by the Commission is PG&E's A/C cycling program where customers may opt for installation of PCT as opposed to a direct load control switch, which you typically see with A/C cycling program.

Auto DR program was authorized by the Commission in 2007. And those results are promising. The Commission's encouraging the expansion of this program in the next utility portfolio cycle.

And then, again, as I stated earlier, we need to be aligned -- or align these programs with the ISO's wholesale market design.

This slide just shows you a couple different things. One is just the progress that's been made with respect to the demand response programs. As you can see back in '03 we didn't

have any price response programs. Today the enrolled megawatts in price responsive is about 1100 megawatts. As you can see for emergency trigger there's a gradual increase up to about 1800 today.

The numbers that you see in here when I say enrolled represent the upper bound, or what we say the high-end potential of the programs, meaning that if every customer who's enrolled in these programs are actually responding when triggered, that's what you would get.

The number, the 465 number, which you see in the price response program row for December 2007, what I tried to show there was what we sometimes call the expected or the performance of the program based on what we have as of today.

So, for the price response programs, what we did was basically take their performance over '07 and represent what happens when they're actually triggered.

Now, the trick with that is that you've got a lot of varying data. We don't actually have a protocol by which to calculate what the expected load -- is. That's one of the tools that we're trying to develop.

But this question always comes up, is what actually happens when you trigger demand response programs. And that's, at this point, our most -- or I guess an informal way of doing it, or informal way of trying to calculate it without a loading protocol in place.

So obviously that's a concern; 465 megawatts actually show up as opposed to the total enrollment of 1125.

The last column there is the demand response goal that was set by the Commission back in 2003. It directed the utilities to strive to get price responsive programs that would equate to 5 percent of their system peak demand.

So if you take 50,000 megawatt, just as an example, what would it be, about 2500. So whichever way you look at it, whether it's enrolled megawatts or expected megawatts, for the price response programs, at least, there's still quite a ways to go to meet that 5 percent goal.

The last item there on that slide at the very bottom is that we're taking a look at this goal and re-evaluating demand response goals. And so at this point the staff of the PUC has proposed some demand response goals for '09 going forward.

And there's the link to see -- draft of some proposed goals. We don't actually address a quantitative goal yet in that writeup.

This is what's coming in very soon next, actually this year. So June 2008 DR portfolio proposals are due, '09 to 11. We just issued some guidance to the utilities as to what the Commission is anticipating or expecting utilities to address in this portfolio application.

Heavy emphasis on alignment with the ISO's MRTU. We want to see better integration of demand response and energy efficiency in terms of customer outreach and marketing, something that's been emphasized in our energy efficiency proceedings.

Expansion of programs that have enabling technology such as auto DR. Finding new ways for customers to participate in both DR incentive programs, as well as dynamic pricing tariffs without double paying them for the load drop.

Encouraging pilot programs, supporting new ideas. John had a great slide there of intermittent load, such as wind. And maybe using demand response as a way to try to integrate that intermittent loading in a better way.

And then we've issued, within that guidance, the criteria by which we're going to be evaluating the DR portfolio, such as cost effectiveness, load impacts, how well does it integrate with the ISO's wholesale market and so on. And for those details you can look up that ruling online.

And lastly, the tools that we're developing. There's a demand response rulemaking that the Commission started in 2007. Two of the key items that are going to be produced by this rulemaking is a load impact protocol and a cost effectiveness protocol for demand response resources.

Load impact protocols are important for long-term planning, resource adequacy, day-to-day operational needs for both ISO and the utility. And they can be used for settlement purposes, to help determine how to actually -- how to fairly pay customers.

The load impact protocol that's being anticipated for a decision by the Commission is specifically for long-term planning purposes. But we see this as an iterative process of continuing to update this protocol so it meets these other

needs.

In addition to that is the cost effectiveness protocol by which load impact protocols would be inputs to that. And the Commission is considering a settlement at this time that's been put forth by the intervenors in that proceeding. And we expect to have it in place to evaluate the '09 to 11 DR portfolios put forth.

And that concludes my presentation.

PRESIDING MEMBER PFANNENSTIEL: Thanks, Bruce. That was a fairly remarkable clear -- remarkably clear discussion of what's going on.

And let me just take a moment to really applaud Commissioner Chong for the work she has done on this at the PUC. She has just taken this an enormous, enormous way. And I'm really encouraged and delighted that we're working as closely as we are. It's such good news that we're really making incredible steps there.

So, thank you, Commissioner Chong.

Other questions?

COMMISSIONER BYRON: If I may, thank you. I agree, it was a very good presentation. Very impressed. Looks like the PUC has been very

busy in this area in recent months. And I look forward to the IOU demand response portfolio proposals that will come out in, I guess it says June here. Good direction on the part of the PUC.

As you know, a lot of heat was generated around here a few months ago, around these PCTs. And I looked back on page 5 of your proposal -- I mean, sorry, your presentation, and note that the PG&E AMI system includes remote connect and disconnect switches. Is that below the radar screen for most people?

Let me put it differently. Do all AMI systems, to your knowledge, have this kind of capability?

MR. KANESHIRO: Well, I know that San Diego and Edison, in their proposals, are including that or have expressed to us that that would be included in their proposals. For PG&E it was not in their original application. So that is now coming back to us, or they're seeking to add that into this upgrade application.

As to whether it's in other systems, I couldn't answer that. I'm not exactly sure.

COMMISSIONER BYRON: Okay. Well, thank you, again, for your presentation.

PRESIDING MEMBER PFANNENSTIEL: Other questions? Thanks, Bruce.

MR. HUNGERFORD: All right, next we have PG&E, Jana Corey will be talking to us about what PG&E is doing. And some more detail, I presume, that will address Commissioner Byron's question.

MS. COREY: That was an absolutely perfect question for me because this is one of my favorite topics, is the technology associated with AMI and end-use technology. So I'm going to talk about that.

I always start with this slide just for the people in the room who don't know who we are. We are in northern California; 5 million electric customers; 4 million gas. One of the things that has happened in California is the ability to invest in demand response and energy efficiency programs because of the way we're structured regulatorily. And I think that's really fantastic.

These are the scoping workshop topics that were in the announcement. And I wanted to just emphasize, I'd like to talk a little bit more in detail about the capabilities of the advanced meters, to your question. And then specifically

how we intend to offer programs to our customers that will allow us to take advantage of what the technologies are offering.

And PG&E, as Bruce really did a good job of laying out, we have a program that's actually in place, in deployment right now. And one of the things that happened with 10 million AMI points going out into the market was it really stimulated a lot of investment and activity in the space.

So what we're seeing is just an incredible turn on technology as people have invested. And they see the promise of the inhome space developing. So we must get an entrepreneur a week in our offices wanting to show us their stuff that they're thinking about for inhome capability.

And it's extremely exciting. And weaving that together, the technology together with the programs and the tariff designs, is a really huge opportunity for our state to show a lot of leadership. So we're very excited about what you all are doing.

We do have, I think Bruce really laid out the demand response programs that PG&E and the other utilities are offering. I would like to use

more of my time to talk about the technology. So, I'm going to move quickly through the programs that we offer.

Specifically this year we have three new offerings, a cafeteria-style program that gives customers some choice in how they design their own program. The smart A/C program, which is our load control program that we offer our customer either an A/C cycling switch, or a PCT of some sort.

And those are really important programs to us. We're just beginning the deployment last year and this year.

Smart rate, which is, I think there was a reference to that, also. That's PG&E's residential critical peak pricing program that we do offer. Associated for customers that have our smart meter, which is our AMI solution. So we are offering that this summer to those customers in Kern and Sacramento areas who have our AMI meters.

One of the things that we wanted to make sure is -- or ask here, is that when we put together demand response programs that we make sure that they're really easy for consumers to understand.

One of the themes that we've continued

to talk about is customer education. And it's really imperative that we make these first ones easy to understand. And maybe they're not perfect, from an economist's perspective, but they get customers understanding the time differentiated nature of energy, and how they can participate in this market.

We also want to be able to offer our customers a suite of products, either energy efficiency, demand response, equipment offerings. We want customers to have lots and lots of choices in order to participate in this energy management project that we're all about.

We also agree that there's a real opportunity to educate customers about what the advantages of demand response are. This idea that there is time differentiated nature of energy.

And I think Commissioner Chong referenced the telecommunications industry. Customers are not unfamiliar with that theme, but they do need to understand that that also applies in our industry.

So we are looking at market segmentation, understanding how customers would respond to different program offerings, and giving

them the choice to respond.

And then my favorite topic, encouraging installation of enabling technology. So we'll get right to that.

PG&E's AMI program is called SmartMeter. And for those of you who have been in the industry, you'll laugh because you can look all over the United States and see MeterSmart, Smart Meter with a gap in between the words, and anyway, it's a very funny little marketing thing that's going on now. Because everybody's really looking hard at the space.

We are looking at upgrading both our electric and our gas meters. We're currently in the field doing that.

Fifteen-minute intervals for large commercial and industrial customers. Hourly for our residential customers. And then daily for gas. Nobody's really mined the gas opportunity. We think there's education and interest in that space, as well. But we talk a lot about the electric side.

And those will allow us to communicate. The new systems that are being developed are allowing us to communicate into the home, which is

the really really exciting space right now.

For those of you also who've been in the AMI space, there's lots of benefits to customers around things like more information. The fact that we won't be traipsing in their yard. Some better revenue cycle performance in terms of bills.

We do have some outage capabilities that are going to come into play when we have all of our AMI systems in place, which is actually an un-mined, untapped area from the reliability perspective. And everybody's pretty excited about what that's going to yield.

And then the opportunity to turn off and turn on a customer remotely, which I'm going to talk about a little bit more in detail in a minute.

Obviously PG&E gets the benefit of all those advantages we provide to our customers, besides getting better customer service to oir customers; we also get the operating benefits from that.

And then, obviously, the real genesis of this whole AMI space was the California energy crisis and the Commissions' interests in having

the ability to provide some kind of real-time or near-real-time pricing to our customers.

So, this is the part that I like the best. So one of the things that's happened is with all this interest in AMI, is that the industry has evolved really really fast. And one of the things that's interesting to me is if you think about the utility business, the energy business, typically the cycles for capital investment are like 10, 20 years. They're very long. You build a power plant; you wait, you know, 20 years, and then you build another one.

What I think is fascinating and fantastically interesting about this space is the cycle times are on the telecommunication pace, three, five, seven years. And the stuff is moving. And, in fact, we began our project three years ago and we've already seen the technology move substantially.

In particular -- so if you see -- anyone notice that? The meter lost its little real cover. What's happened is in the meter space, and this is really to your point, Commissioner Byron, one of the things that's happened is everybody's looked at the advantages of having a disconnect

switch within the meter.

And the economics of that, if you think about it, are really replacing a guy going out and turning the meter off and coming home. And then a guy going out and turning the meter on and coming home.

And so if you think about the increasing costs of labor and the advantage of doing that remotely, that becomes a very economic proposition. And what's happened also is the price of the devices have come down substantially.

Our first case we had looked at the pricing and they were in the $100, $120 range. And for those of you in the market now, you know they're in the sub-$50 range now. I won't tell you any more about the detail about the numbers, but the percentage reduction in prices of that disconnect switch are so dramatic over the last three years it makes it a very economic proposition for utilities to put it in their meter.

And one of the things I think is going to happen; in four or five years you probably won't be able to buy a meter without a disconnect/ connect switch in. I'm sure of that. That's my

little projection.

The second thing that's happened is the --

COMMISSIONER BYRON: Well, good, then I'm sure -- over here, over here -- I'm sure that the American Thinker will be glad to interview you.

(Laughter.)

MS. COREY: Okay, well, let me -- I did want to say one other thing about that is the disconnect switch is, it can be -- one of the ways that it can be used, now this is the other thing, is that all of the elements of the new meters are now remotely configurable.

So the meter, the metrology, the meter reading part, the disconnect switch, the home area networking devices, each one of the AMI communications device, all of those are becoming remotely configurable.

And what that allows you to do is it allows you to a) protect your investment, which is really important; but, b) to the extent that this cycling on technology in this telecommunication space is beginning to yield opportunities for customer offerings. That's going to allow us to

take advantage of that.

Now, you can't change out the hardware again, but you can change out the software and the firmware, which is hugely exciting.

So on the disconnect switch we have the ability to program into the meter potentially a load-limiting service just like what Mr. Schomberg, I believe, referenced in edf.

Now, maybe that's something we'll never do in California, but we do have the ability to offer a service to do some kind of prepayment program. A prepayment program has been shown to be very attractive at Salt River project. They're interested; they offered it; and they got a lot of takers.

So there's an opportunity to use this technology to offer our customers some really exciting new services.

The third area is the home area networking. And that's been an evolution. Probably two years ago our customers in Silicon Valley Leadership Group, when we filed our case, they were pushing hard on us to offer that in every meter. And it wasn't economic at the time.

But what's happened is it's become,

again, the technology has become much more economic, and there's a lot of excitement about what you can do in the inhome space. So it suddenly becomes economic to put that under the glass and communicate two primary things into the home.

Number one is information. And we think that there's a huge value to our consumers to have information available to them. So, number one, the home area network is going to provide energy information into the customer's home.

Number two, it will allow us to offer programs to consumers that they could potentially take advantage of.

So, one example that we have in our current case on file at the Commission, is that we would do our A/C cycling program now over the home area network instead of as a third-party service offering. So we think that's an opportunity for our customers to sign up and participate in a utility-offered program. Or maybe it's just an inhome display; or maybe it's an energy management system. There's lots and lots of ideas that people have about what's going on in the home.

PRESIDING MEMBER PFANNENSTIEL: Jana, I

just want to make sure I don't take away the wrong impression on this. Is your home area network offered as part of your AMI? Or is that a separate offering to customers that -- I'm not sure how that fits with your AMI installations.

MS. COREY: Okay, let me clarify that. The current products that we are installing today do not have home area networking devices on them, because we were coming out of the chute three years ago when that was unavailable.

We have an application at the CPUC to include that on a go-forward basis under the glass in the meter. And all it does, it's a transmission device, a communication device that goes on the meter, under the glass. And it communicates into the home.

Now, what happens from the wall in the home is not -- we don't currently have anything to do with that except we have said we want to take our A/C cycling program and put that on our --

PRESIDING MEMBER PFANNENSTIEL: Well, how does it communicate into the home? I'm still struggling with what is the device in the home that would be part of this.

MS. COREY: Oh, what would the device in

the home be? Well, first of all, let me tell you what the device under the glass is.

There's current market offerings in two technology solutions. One is an RF solution. So it's a little radio and it just puts data out into the home.

Or the second is a powerline carrier solution which says it's got a device under the meter that the information goes over the wire into the home.

Now, you have to have something on the other side, right, that hears the RF signal or picks up the powerline signal. And that can be any one of a number of devices such as we have displayed here on this chart.

PRESIDING MEMBER PFANNENSTIEL: I see, so that's just -- those are customer options that are --

MS. COREY: That's right.

PRESIDING MEMBER PFANNENSTIEL: -- being described, but they're not actually something that PG&E would put in the home?

MS. COREY: That's right. We think that there's a huge -- and this has really been exciting, because if anyone in the room went to

the Consumer Electronics Show, there was a whole half a floor full of people that are in this, energy management systems, smart light switch, inhome display, smart thermostat, in this space creating products. It was fantastically exciting.

We had a venture capital forum in our offices where we brought VCs from the Silicon Valley up to talk about the space. And they're very excited. Whirlpool, GE, all the big appliance manufacturers are really excited about what they can put in their devices that'll talk in this ecosystem.

So the utilities are putting in place the fundamental sort of elemental piece of this home area networking system. That answer your question?

Going to have to show my little picture here. So, we're speaking from the home area networking gateway that's in the meter either to inhome display, a smart thermostat or plug-in hybrid. And that's a two-way communication. That's really important. And it has to be using an industry standard.

So, one of the critical factors in this picture is that people who are developing products

within this inhome space have to be able to understand how to plug their product into this network. And that's a really critical factor.

Do we either communicate directly from the home area networking gateway in the meter to the device, or you can communicate into a home energy management system that actually runs the energy management system, itself.

So there's a couple of choices with the way this is going to evolve. The good news is we don't have to decide that today. This is where the industry is going to move. It's going to move the market. It's a consumer electronics market and we'll just see it move like consumer electronics.

COMMISSIONER CHONG: Jana, is the industry standard being set by these manufacturers of the devices?

MS. COREY: Well, it's a very interesting dynamic right now because the three California utilities and probably a dozen other utilities from around the United States, vendors, anybody who has an interest in the space are trying to figure out what the right standards are for these devices.

And rule one for us is to pick something that's not proprietary to the utility industry. We're trying to buy, you know, think about radio pricing and radios that go down with the entertainment industry price curve are going to be a lot more cost effective in these inhome devices than some proprietary radio device.

So the industry is -- there's a number of organizations that alliances that are trying to push one standard over another. And it hasn't been finalized yet. And as long as the interfaces -- I mean I think one of the key themes here is interoperability. So you want to be able to plug one thing into another without having to, you know, reconfigure your plug.

The other thing is we want to make sure that these are extremely easy for customers to use. Right now you can buy a system just like this, but it's $1500, $2000 to put this in your home. It's not cost effective for the mass market. And what we want is something that's more $100 price point, or that's accessible to all customers.

So, it's got to be inexpensive, and it's got to be absolutely easy to use. So those are

the things. Yes.

MR. BERBERICH: If I could just add a comment on the technology. There are multiple technologies that have emerged in this space. And there are dueling communication protocols. And I think as you design these programs, setting up the communication protocol, because otherwise we're going to have divergence and they're not going to be able to interoperate.

And so that is certainly something that needs to be on the agenda.

COMMISSIONER CHONG: Are you suggesting that a regulatory agency set the standard? I just wanted to clarify what I heard.

MR. BERBERICH: I'm not suggesting regulatory industry set it, but there are -- what we want to do is make sure we foster something here in California, I think. And I think it's critical that there can be multiple standards, but we don't want to have hundreds of standards.

And as the market is developing as Jana indicated, there are hundreds and hundreds of vendors that are coming to the market right now with products. Many of them with differing standards.

And I'm not necessarily suggesting that it ought to be a policy, but it ought to be something that ought to be considered, I think, as we think through this, for sure. Because interoperability will be important.

COMMISSIONER CHONG: I'm sorry, Jana, we're having a little exchange here --

(Laughter.)

MS. COREY: No, that's perfectly fine. I'm just --

MR. BERBERICH: We'll get back to you.

COMMISSIONER CHONG: We'll get back to you in just one second.

(Laughter.)

MS. COREY: Okay.

COMMISSIONER CHONG: Okay, that's great. I do not believe that regulatory agencies should pick standards, first of all. Because we're the last guys to get it right.

However, I do think that you're right in that we shouldn't have too many standards. But I think what I'm hearing from business, by the way, when I'm down in Silicon Valley, is they're saying please get around to it really soon because we're just dying to go, you know, they're raring to go.

And I agree with you that that's the important thing. But, you know, think back on phones. The way they did it is they let the industry set a standard. But once a standard was set, people knew that if they plugged it in the wall it would work. And that's the whole benefit, right?

And by the way, I just wanted to note my hybrid does not look like the one in Europe.

(Laughter.)

MS. COREY: I hope yours is more attractive, by the way. I'm sure it is.

I think one of the key things here, too, is the ability to download software into the devices. And as long as the technology is constructed properly you can actually move to a new communications protocol.

And we're very big fans of internet protocol, because internet has great security. It's very scalable. It has a lot of -- there's a lot of elements that we like about that. People put trillions of dollars against IP issues. So we're trying hard to figure out how we can use that to our advantage. Jackie.

PRESIDING MEMBER PFANNENSTIEL: I was

going to -- Richard Schomberg would like to say something on the question of standards, I think, since he's been working on it. Right? You can comment on that?

MR. SCHOMBERG: Yes, thank you. I understood what you said both. And, of course, the regulatory agency doesn't want to set the standard, which would be -- might be a wrong thing.

But we are in a "Catch 22" situation. This industry is in a "Catch 22" situation. And it's a vicious circle where actually I think that all the players have been moving too far before starting to address the standard question.

And this is the worst that you can experience. That means there are many vendors that have invested a lot of money developing their own line of products. And establishing a standard would mean for -- it would mean that one would be elected, a good one. And all the others would have to change actually their entire line of products.

It's not going to happen by itself. I guess in the cellphone industry the people were not that far so that they could agree more easily.

So, and just to stop here I guess there would be a huge value for an independent body, or even a regulatory body, to create conditions so that the main parties really get together and work that out until they agree on the standard.

And to me, the intent of all the work I've been witnessing on the PCT actually I was amazed -- well, technology, I love it, but I was amazed because to me the PCT work up to now has been actually to get the people together to agree on some kind of standard.

So the punchline, of course, I guess cannot set the standard, but you can create conditions so that a standard starts to emerge. And then you can get the standard body to then do the work. But the standard body cannot do it -- I have a standard body, I know what it can do and not. I know it is not going to happen by itself.

MS. COREY: Okay, well, since I have the mike next I'm going to just make one other last comment on this --

PRESIDING MEMBER PFANNENSTIEL: Actually, Jana, hold on, as Commissioner --

(Laughter.)

ASSOCIATE MEMBER ROSENFELD: Jana, I'm

sorry. I want to make one brief remark to answer Richard. And to remind Commissioner Chong.

There is a utility industry association called (inaudible) HAN. The HAN stands for home area network. They have produced a reference design. It was originally thought to go the entire 24, and would have been the basic communications standard. That's off the table right now.

But it does have the following desirable properties. It chooses one very elementary one-way communication default built into the device. It then has an extension port required so that each utility can put in its own, like a USP memory stick. So it's infinitely compatible.

And we would be -- this is a discussion not for the scoping discussion, but early on the May agenda, it will be very desirable, I think, to preserve that and honor that, and somehow or other work that into the -- work that -- into the present situation.

Jana, back to you.

MS. COREY: Thank you. Sorry for interrupting. I'll refrain then from my comment. That's well said.

So I guess in summary for PG&E, we think that demand response obviously is an important tool to manage peak load in California. That's stating the obvious.

We do think if the building standards were to require PCTs it would give a jump start to this industry. And we think making it accessible and familiar and out there in front of customers, the device itself, might give us an opportunity to market to them a program that they could take advantage of the PCT because they already have it in their home.

So, we're supportive of some kind of requirement in new construction and permitted retrofitting, because we do think it underwrites the development of that industry in a fairly friendly way to consumers.

Also we think that the home area networking space is really exciting. And we think there's a lot of opportunity to offer our customers voluntary programs that they can take advantage of.

And as Ahmad pointed out, the imagination is really the limit on what we could do for our customers with this equipment in the

home.

So that's our support for that. Thank you.

PRESIDING MEMBER PFANNENSTIEL: Jana, I have a couple questions on the PCT recommendation. First of all during the controversy showing up in the newspaper and the Legislature, did PG&E step up and say this at that time?

MR. SPEAKER: No.

MS. COREY: Okay.

MS. SPEAKER: We did have questions from reporters and this is --

MS. COREY: Right, this was our -- our position is that there's two questions here. One is what kind of equipment do you want to put in people's homes. And the second is what kind of programs do you want to offer a customer.

And if you want to offer a customer a program, it must be voluntary. And PG&E's a very huge supporter of voluntary CPP, other voluntary programs. We've been very consistent, I think, in our position on that.

But having the devices be mandatory does underwrite that industry a little bit.

PRESIDING MEMBER PFANNENSTIEL: Then the

second question is that very one about underwriting the industry, by which I guess you mean the whole home area network industry? Or the technology application industry?

And what I'm trying to figure out is if the PCTs go into the building standards then they get phased in over some very long period of time, right, on new construction and some retrofits, but mostly new construction. Which, let's assume, I don't know, 100,000 homes a year or something like that.

Meanwhile, AMI will have saturated, presumably, the residential market well before this happens. So I guess my sense is that AMI is going to be the one that's in the lead, that's going to set the technology needs for the inhome technologies. And PCTs are going to be coming along later.

Do you see that? Do you not see it that way?

MS. COREY: Yes, I think, sort of if you have the perfect construction everybody would have an AMI meter. And then you would go out and market inhome devices that would hear the information from the AMI meter. If, you know, you

had infinite time and whatever.

You're right, that would be right, the progression. But I don't think we want to want to begin to start developing customers' interest in or familiarity with how to use inhome devices. They're already available.

PRESIDING MEMBER PFANNENSTIEL: No, I agree with that, and that's what I'm really saying, is that the smart meters are going to be in the homes way before PCTs. Even if PCTs were in this round of the building standards, which presumably is not going to be. The meters are going to way precede the PCTs.

So I'm not sure why you would think that the PCTs then are going to be setting the groundwork for what should be in the home. Because they're going to be coming later; they're going to be phased in over a much longer period of time.

MS. COREY: Well, if an AMI meter -- every home had an AMI meter, was communicating information into the home, as soon as that meter was communicating into the home you'd like to have an inhome display or some kind of device in the home that could take advantage of that.

PRESIDING MEMBER PFANNENSTIEL: Well, I think the PCTs sound like, at least, an excellent device. And once you have a smart meter, then it seems like the homeowner would probably want to run out to Home Depot and buy one and put one in, rather than waiting until they moved into a house that was built post-2011 building standards, so therefore it already had a PCT in the house.

MS. COREY: Yeah. No, I --

PRESIDING MEMBER PFANNENSTIEL: It seems like you really have the cart before the horse in terms of when the timing of this, why PCTs would underwrite the growth in the smart metering program.

MS. COREY: Well, our view is that we would expect to market other DR programs including PCT programs, if those are the way the programs group decides to go.

It's not just in the building standards. We would continue to market -- I think Edison has a very big program to market PCTs. I mean we would continue to -- we have a big A/C cycling program that's going out and putting PCTs in today.

PRESIDING MEMBER PFANNENSTIEL: Well, I

think marketing PCTs and offering PCTs are very different than putting them in the building standards. And it's putting them in the building standards that I'm questioning.

MS. COREY: I guess I see it as an opportunity to get those in those new homes today. And as soon as we got a meter in there, they'll have the ability to communicate.

PRESIDING MEMBER PFANNENSTIEL: Then the other question is really much more fundamental. Why did you pick that technology? Why do we think that the PCT, you know, you mentioned awhile ago that there are hundreds of vendors coming in with different technologies.

And, you know, I was down in Silicon Valley last week and apparently virtually everybody in this room has been down there talking with the various entrepreneurs and what they're creating.

(Laughter.)

PRESIDING MEMBER PFANNENSTIEL: And what they're creating, in my mind, is a long way from a PCT. It's information that customers then can do something with on a voluntary basis. And PCTs may be the old technology.

MS. COREY: I think if you look at the whole host of products that you can have in a home that you'd want to use to adjudicate energy management, I mean I think the long-term vision is you have a home energy management system that is communicating to every energy usage -- high energy use device in your home. And you run your dishwasher, then you run your washing machine, and your duty cycle, your refrigerator in between that to try and make a flat load profile. Or to reduce your load footprint.

If that's sort of the grand scheme, you've got to start somewhere. And I think the PCT actually does have a significant control over your load.

Maybe you'd put it in the refrigerator, or some high-energy use device. But at this point the appliance manufacturers are not --

PRESIDING MEMBER PFANNENSTIEL: Well, the PCTs that are being -- that work, the building standards for thermostat controls, programmable communicating thermostats for the home --

MS. COREY: Right.

PRESIDING MEMBER PFANNENSTIEL: -- presumably for air conditioning usage.

MS. COREY: Right. Which tends to be the peaky use, right. So.

ASSOCIATE MEMBER ROSENFELD: Jackie, I would just remind you that we're seeing a state in which there are literally 30 percent of our demand is available for short times in -- thermal storage. Which means you can cycle in the morning and raise your thermostat in the afternoon.

So I think John was saying the same thing. You want eventually to do a lot of things, but the first thing that comes to mind is the air conditioning. The second thing that comes to mind is the pool pump. The third thing that comes to mind, if there's much of it, would be electric (inaudible). And this was just one device out of a menu of devices which eventually we're going to get to.

PRESIDING MEMBER PFANNENSTIEL: Yeah, and I am absolutely in favor of that. I think that we do need to look at the whole menu of devices and decide which would be the ones that would make the most sense from individual consumers' standpoint.

Thank you, Jana.

MR. HUNGERFORD: All right, thank you,

Jana. And next I guess because Larry's coming up here, I guess Larry Oliva from Southern California Edison is next. And he will be giving Edison's perspective on these issues.

MR. OLIVA: Thank you, David. Thank you to the CEC and CPUC to allow us to be here today. And I want to thank the Commissioners also for asking PG&E all the tough questions.

(Laughter.)

MR. OLIVA: There's none left for me.

PRESIDING MEMBER PFANNENSTIEL: Maybe not.

(Laughter.)

MR. OLIVA: Jana did a good job in answering them.

We support the CEC's and CPUC's efforts to promote demand response with tariffs and with enabling technologies. We also support the Cal-ISO's efforts to include demand response in their electric and energy markets. And we're working with John Goodin and his staff, along with the other utilities, to enable demand response to participate in the markets when an MRTU is implemented.

I'd like to provide you a lay-of-the-

land of demand response at Southern California Edison. First of all I'll tell you about what we do. I lead a department that runs our demand response programs.

We design, implement and operate our current demand response programs. And we're also responsible for implementing our programs when AMI is implemented.

Our department, TP&S, is within our customer programs and services department, which has energy efficiency and customer experience management in it. So we are working to, you know, integrate and create synergies among energy efficiency, demand response and our customer experience group to make sure that we are being most efficient in presenting programs to customers. And also, you know, finding ways, particularly in marketing, that we deliver a suite of services instead of just a program here and a program there.

Our current programs include a radio-controlled type program, our summer discount plan. That's the SDP. Our agricultural pumping program, which are interruptible programs.

We have emergency interruptible rates,

that's our interruptible I-6, or BIP rates. Our voluntary price response programs, which are demand bidding, capacity bidding and critical peak pricing. And we have a contract with an aggregator who provides a program like our CBP. And that's EnerNOC.

We have 1300 megawatts, or about 5.7 percent of our total system peak, in demand response with all of those programs. And that's where we are as of the end of 2007.

In 2007 we increased our summer discount plan by 225 megawatts, which was a huge increase, almost doubling the size of our program. And that is the largest demand response direct load control program in California.

We also have 639 megawatts in 30-minute demand response available for emergencies. And we have 42 megawatts in day-of and day-ahead in four different programs.

I just wanted to also show you another way to think about the demand response programs we have. We have what we call firm and dispatched. So this is where we have control of the switch.

The customers agree that we can activate these switches, and that's our summer discount

plan and our ag pump program.

And then we have firm demand response where the customers have agreed to participate. And if they don't they are subject to a penalty. And that's the interruptible I-6 program and our capacity bidding and the third-party EnerNOC aggregator programs.

And then we have the nonfirm programs, which are demand bidding and critical peak pricing. But, you know, there is a difference among these programs in terms of how the utility thinks about it when we dispatch or activate demand response from these programs.

I wanted to just show you where we are with the price responsive type programs. And as this chart shows, this bar chart, the little tiny stack at the bottom is where we are with our price responsive programs for large customers.

Now, this does not include default critical peak pricing, which we are proposing in our GRC phase two. So we have not included that in this chart.

But in this chart we show in the purple bar, the second bar, is our SmartConnect demand response. That is the demand response we expect

to get from our peak time rebate, our critical peak pricing and time-of-use.

And then the top bar is from demand response contracts that we have pending for approval before the Commission as we speak.

And so we would, with just those programs we would hit a 5 percent target in price responsive programs by 2013. Now, if we get another -- we have, on our large customers, about 200 kW. We have about 12,000 of those customers.

Two thousand of them are already participating in our demand response program, so there's 10,000 who are not. When we go to default CPP for those 10,000 customers we expect to get some more demand response; it's just not counted here.

So let me turn to where we're going with demand response with our Edison SmartConnect meters. And we use SmartConnect as our name for the program because we believe it's the connection with the customer that's smart; that is providing them information in price and usage. That's the critical thing about what we're offering.

With our SmartConnect program we'll be offering residential peak time rebates. And

that's our primary mechanism for getting demand response, while there's AB-1X. We're also offering voluntary TOU and critical peak price rates, which will be for residential.

And for our C&I customers about 20 kW, we would offer them default TOU and optional CPP.

We're also proposing enabling technology using two-way programmable communicating thermostats. The technology would be used to help enable critical peak pricing as well as our peak time rebate.

And what we'll be proposing in our GRC phase two is the peak time rebate. And there'll be two basic rebates, similar to what San Diego has agreed to in their settlement. And that is that we rebate for peak time load reductions without enabling technology. And there will be an increased rebate or a higher rebate for customers who use enabling technology to provide their load reduction.

This is our roadmap which shows you where we're headed over the next four years. This year we're filing our GOC phase two. We have pending before the Commission our application for Edison SmartConnect.

We're also doing some trials. We're doing a pilot, a non-ZigBee pilot, which is basically we're looking at a smart thermostat that really, for the behavioral aspects of what kind of load reductions we get under different program designs.

We'll follow that with a pilot next year with a ZigBee enabled thermostat that works with our meters, so we'll be able to test the technology.

2009 will be a pilot year where we will test the PTR in a pilot. We'll also be enabling our remote service switch. And Commissioner Byron is not here, but I wanted to make one comment on the service switch.

I think Jana answered the questions very well, but there's one point I wanted to make. With respect to the on/off switch, most utilities in large urban areas have remote on/off switches for some of their meters.

These are meters where the customers are credit-challenged, or university towns where there's a lot of moving in and out. In those utilities there are a lot of rules about, you know, when they turn on and off, to protect the

customer.

Now, when we were looking at this we felt that it would be great to have it integrated into the meter because our population, we have about a 25 percent churn. So we have a lot of people moving in and out. And we have universities, we have credit-challenged customers. And so if we could get the cost of it down, that's why it made sense for us. And the way to get the cost down is to put it in every meter.

Finally, on the customer education part of it, -- well, let me finish with the launching. We'll be launching these programs in full, the PTR and the thermostat programs, et cetera, in 2010.

And in the line you can see the meter rollout. By 2011, 2012, we will have our 5.3 million meters installed. So we'll be doing our pilots in the early phases when they're not that many meters installed. And then we'll be launching when we have, you know, roughly half of the meters installed.

On the customer education part, I just wanted to make a point that I love the analogy of hammer and anvil. And you have to make sure you don't hit yourself on the thumb. And the thumb is

really the customer.

And it's so, as Commissioner Pfannenstiel pointed out, it's so important to provide customers information to build their awareness. And Richard Schomberg also mentioned this. To spend time with the customer and to help them, you know, get educated on the programs that are available and the techniques that can be used.

So we have to make sure that we can, when we ever deploy rates and programs, that we have the opportunity and put the effort into educating those customers.

And that's what I have. Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Larry. Questions? No. Thank you very much.

MR. HUNGERFORD: Thank you, Larry. Now we'll move on to San Diego Gas and Electric. And I believe Ted Reguly is going to be doing the presentation for them.

MR. REGULY: Thank you, David. And I'd also like to thank the CEC and the CPUC for inviting SDG&E to talk about this topic.

I'm going to talk about three basic areas. Going to give you a brief overview of where we are with our AMI deployment. The name of

our project is Smart-space-Meter program.

(Laughter.)

MR. REGULY: Then we'll talk a little bit about enabling technologies; some of the views that SDG&E has around PCTs. And then I think Bruce actually did an excellent job covering our recently approved DR rates. So I'm not even going to go into that.

Smart Meter benefits. We are very much into customer choice at San Diego Gas and Electric. A couple recurring themes that I've heard here today, and it really is about customer education and customer choice.

We did see what happened with the most recent PCT incident, talking about mandating customers to do something. And San Diego Gas and Electric is not for that at all.

Already been mentioned, things like outage notification. We have been doing, we have piloted various technologies down in San Diego and done focus groups.

Customers to want to get more information and want to better control their energy usage. The problem that we see today, especially with our residential customers, they

only see it at the end of the month. And they see a monthly consumption bill.

With AMI and other changes that we're making at San Diego Gas and Electric, we really see this as a way to change the way we relate with our customers. Improved customer service, satisfaction and lower overall costs of our commodity.

This gives you a little bit of an idea as what was mentioned earlier, I think it was, by Bruce. We did get approval, CPUC approval, to move forward last year.

As part of our settlement we did enter and get an all party settlement in our case. Two things that we added to our case as part of that settlement was the integrated remote disconnect and working on an industry standard home area network.

And I really want to applaud the industry on what it's done in the last years. There wasn't such a thing when we entered -- when we agreed to start moving on an industry standard, home area network communication interface. And I think through the work of utility AMI, open hand, others, great progress has been made in that

arena.

What we have been doing since March is we have been working on our back office systems. We plan to get that done October of this year so that we can start mass deployment towards the end of this year.

We are in the midst of signing our AMI technology in the installation contracts. And we'll be filing that with the Commission hopefully shortly.

I think I already mentioned that we are going to be rolling out 5000 end points in the Tierra Santa area of San Diego County in June of this year. And then we do have plans to make all our system -- get all our system integration work completed so that we can support peak time rebate and other dynamic rates September of 2009.

Another recurring theme that I've heard today is we feel, and I think the industry also supports this, that Smart Meter or AMI infrastructure is foundational for utilities moving towards a smart grid. And if you can see at the top of the pyramid it's really a smart home.

And when people talk about the smart

grid it's really two-way communication and control laid over the distribution system.

This is SDG&E's view of the home area network; not quite as colorful as Jana. It doesn't, you know, go in and out. We do not see the meter as the gateway into the home. We see that there is going to be various other gateways, internet service.

We do not think that the utility should own or isn't even going to dictate what goes on in the home.

The reason why we were very staunch proponents of an industry standard is we want to be able to plug into a home area network that I think, as Jana mentioned earlier, is happening.

The whole AMI industry is changing. Going to home area network is part of the total service offering. And also if you can see what's going on in the home, home automation is becoming, the price point on that is coming down. And it is moving towards more of a standard based area.

PCTs. We do support PCTs in all new construction and remodels. One of the reasons for that, especially in southern California when you look at the peak duration curve, what is really

causing that real steep spike for the few hours in a year, it is A/C load.

And we see A/C PCTs as a way to control that. We see it as a very user friendly interface, much better than A/C load cycling. And cost effective. To the point that we included 57,000 PCTs in our AMI case, and will be rolled out as part of our AMI deployment for our small and medium C&I customers.

PRESIDING MEMBER PFANNENSTIEL: So you'll offer the PCTs with the AMI?

MR. REGULY: Yeah, for --

PRESIDING MEMBER PFANNENSTIEL: So only --

MR. REGULY: We're talking 1.4 million customers. And out of that we were able to cost justify it for 57,000 small and medium C&I customers. We'll get that. The money for that is already in our filing. And we will plan to be rolling that out with our AMI deployment.

PRESIDING MEMBER PFANNENSTIEL: And how are these customers chosen, the ones that will get the -- how are you going to cost justify just that many and not all of them? Why wouldn't all customers? Why would it be cost justified for

everybody?

MR. REGULY: Do you know the answer to that question, Mark? I'm calling my other expert up --

PRESIDING MEMBER PFANNENSTIEL: Okay, great.

MR. GAINES: Mark Gaines with SDG&E, Director of Customer Programs. The 57,000 is targeted to the small and medium commercial customers because those are the ones that were least price sensitive. So the only way you could -- when we did the analysis if you imposed CPP type rates upon them you would get very little response from them.

The only way to get it is to have the enabling technology on top of that. So, it was identified for that segment only.

PRESIDING MEMBER PFANNENSTIEL: So, these are commercial customers?

MR. GAINES: Yes, small and medium.

PRESIDING MEMBER PFANNENSTIEL: Are they, then you will control their air conditioning --

MR. GAINES: This would be a voluntary program --

PRESIDING MEMBER PFANNENSTIEL: They will have decided that they volunteer to have the PCT put in?

MR. GAINES: Yes, they volunteer to put it in, or to have it put in.

PRESIDING MEMBER PFANNENSTIEL: And then you give them some price --

MR. GAINES: And we give them an incentive to make that happen.

PRESIDING MEMBER PFANNENSTIEL: And it's not cost justified for residential on that basis?

MR. GAINES: It wasn't at the time.

PRESIDING MEMBER PFANNENSTIEL: Thank you.

MR. REGULY: The last slide just goes more into our demand response rates that were approved as part of our GRC phase two.

And with that, I am pretty much done. Is there any questions?

PRESIDING MEMBER PFANNENSTIEL: I have none. Any questions? Yes, Commissioner Chong.

COMMISSIONER CHONG: I just wanted to explore that PCT issue one more time. So maybe we need the other gentleman, the expert who so kindly leapt up at that moment.

So, when you're talking about the small and medium commercial customers, you're talking about mom and pop stores, dry cleaners, small grocery store, that type of customer, is that right?

MR. GAINES: Yes.

COMMISSIONER CHONG: I see. So the alternative to a PCT would be, for example, an A/C cycling kind of program?

MR. GAINES: Yes.

COMMISSIONER CHONG: Is that correct? And what are the differences in terms of installing A/C cycling switch versus a PCT? Does it represent a large inconvenience to the small and medium customer to have either of those programs installed?

MR. GAINES: No, I don't think it's a large inconvenience either way. We think that the PCTs are better because it gives them control over what's happening in their store.

With the A/C cycling it gets shut off and whatever the temperature creep is inside the store happens and they have to live with it. With a thermostat it's controlled by a temperature adjustment of 4 degrees, up to 4 degrees. So they

know that it's never going to get more than that before it turns back on again.

It also gives them notification when it's happening. So it's just much more customer friendly. It also gives us feedback of whether something did happen, whether the air conditioning was actually operating when we sent the signal. So we know better how much reduction actually occurred. So it's much smarter than just the A/C cycling.

COMMISSIONER CHONG: I see, so A/C cycling utility, the customers volunteered for both programs, and on A/C cycling the utility turns off the air conditioning when there's a lot of load, correct?

MR. GAINES: That's correct.

COMMISSIONER CHONG: And so therefore there is less customer control over what happens to the temperature then?

MR. GAINES: Yeah, right. There is no override --

COMMISSIONER CHONG: That's what you're saying? Okay.

MR. GAINES: -- opportunity.

COMMISSIONER CHONG: Correct. And then

under the PCT program they've agreed in advance it won't be more than 4 degrees, 2 degrees, whatever it is, and they know that it's more control, is that correct?

MR. GAINES: That's correct.

COMMISSIONER CHONG: Great. Okay. Thank you, I understand now.

MR. REGULY: They also have override capabilities --

PRESIDING MEMBER PFANNENSTIEL: If you're going to speak you need to speak to the mike or you won't get picked up at all.

Mark, before you go back, just about what percentage of your customers to whom you offer this do you expect will take advantage of it?

MR. GAINES: It's about half of that size range that we are hoping to convince through incentives to install the PCTs.

PRESIDING MEMBER PFANNENSTIEL: Thanks. Would you offer these to residential customers who would not be offered, or are they something that, say, the resident, that you could provide information and a residential customer could go to Home Depot and buy them and install them,

themselves?

MR. GAINES: We fully expect to have a program incenting customers to install PCTs in the home. Our peak time rebate, as it shows here, is a two-tier program, the $1.25 per kilowatt hour requires some sort of control. Most likely that would be either an air conditioning control or pool pump control.

So the economic incentives will develop over time. And as the price of PCTs come down, as they have dramatically, we expect that the adoption rate will occur on the residential side as well as the commercial.

PRESIDING MEMBER PFANNENSTIEL: Great, thanks.

ASSOCIATE MEMBER ROSENFELD: Can I ask you to embellish that a little bit. You said that at the time, a few years ago, when you contemplated all this, that the PCT was not necessarily cost effective for residential customers.

But you also just said that the prices have come down dramatically.

MR. GAINES: That's right.

ASSOCIATE MEMBER ROSENFELD: And right

now if I listen to the manufacturers, the cost of a communicating thermostat will be $20 or $30 more than the cost of a required setback thermostat.

So, do you believe that as of today they're going to be cost effective for residential customer?

MR. GAINES: We suspect that if not today, very near in the future. That's one reason we supported the Title 24 standards. I think once you set that standard that helps drive the price down, because they know how to construct it to make it fit into the marketplace.

And then secondly, just the overall demand increasing would reduce the price. So, we fully expect it to be cost effective if not today, then in the very near future.

ASSOCIATE MEMBER ROSENFELD: That's Schomberg's mass market -- thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you. David.

MR. HUNGERFORD: All right, we're going to get a slightly different perspective now. Jim Parks from Sacramento Municipal Utility District will be telling us what they've been doing to achieve demand response in their service

territory.

Thanks, Jim.

MR. PARKS: Thank you. We don't have a name for our program, but it's going to be something like SMUD's Smart Meters, or something.

(Laughter.)

PRESIDING MEMBER PFANNENSTIEL: Smart Meter Home Space --

MR. PARKS: Yeah, there's got to be something, Smart's got to be in there somehow, and I'll factor SMUD in there, too.

You know, similar to the chart you saw earlier from John, we have a load duration curve that looks like that. And we need basically the equivalent of a good sized power plant for 50 hours a year.

So demand response and load management is pretty important to SMUD. We'd like to figure out some way to whittle down that demand that we have right there for that 50 hours a year.

Our system, in spite of our aggressive energy efficiency goals, is expected to grow by 15 percent over the next ten years. And we have the highest utility goal as a percent of sales of any utility in the state, and we're still going to be

growing.

The other problem is we see that our demand is growing faster than our energy. And so when you talked earlier about a 5000 megawatt load in the state, or 50,000, sorry, I figured out that we were probably, you know, between 6 and 7 percent of that peak demand. But yet we're only 4 percent of the energy. So, from SMUD's perspective the peak demand is a big deal.

Also, by 2012 some of our contracts are going to expire, and so we're going to have to enter into new contracts, because it's certainly not enough time to build new power plants. And I'm not really that hopeful that those contracts will come in at a super low price.

Some of the things that are important to municipal utilities, I guess I'll kind of speak on behalf of all of them for a moment. Local control is kind of a big deal for us. And so when we hear about, you know, possible policies and things coming down that are guiding us, I think what we would request is kind of more of a high-level policy that would give us the flexibility to figure out how to meet those goals, rather than really specific policy that doesn't give you any

flexibility.

The other thing that SMUD is working on that is policy is what we call the compact with the customer. And some of the elements that are part of that, you can see bulleted right here.

And I highlighted the three that kind of stand out with respect to this process. That we want a robust AMI infrastructure. We want rates that are going to reflect time differentiated costs. And we do want strong and active dispatchable load management programs.

We did hold a series of focus groups, approximately 40 focus groups, with no more than 12 customers in all the major customer classes. And I'll talk a little bit about some of the results that we got from that with respect to load management.

The only reason I put this slide in here is just to show that we had started out going down the automated meter reading path. And we had approved that, and we were beginning mass deployment of automated meters, which would not have given us the same flexibility that you would get from advanced metering infrastructure. We stopped that process midway through, and now we're

going with the AMI.

AMI requirements, I think this is similar to what other people have talked about, so I don't really need to hit on that too much.

We haven't issued our RFP yet. We're expecting to issue that in April and select a vendor by the end of the year. And then we're going to have a three-year deployment, so we're going to go from 2009 to 2012.

The way the project is going so far I would probably expect that to kick out a little further because we were planning on issuing the RFP in '07. It didn't happen. So, things being as they are, we may kick out a little bit. This is our plan right now.

We're going through a rate process right now. Not an official rate proceeding, but we're talking to the Board about rate concepts. it's like what can we do.

And the Board has kind of established policy that says we think that the rates should reflect the cost of energy when it's used. So, in other words, some sort of time-of-use rate.

And it should reduce its use on peak. As I mentioned earlier, we have kind of a peaking

problem. And it should also offer flexibility and options. You can look through the rest of the slide to see the other ones. There's other things that we want to do that are also important, with our rates.

So, the concepts that are under consideration at this point. Basically it's time-of-use rates and the ability for critical peak pricing in all of these customer classes, starting with residential on up to our large commercial customers. And so we believe that the AMI will give us that ability.

We're doing a few pilots right now with small commercial and with residential. And on the small commercial we are using the PCTs. And we see that as a great option, understanding some of the drawbacks.

The focus groups' findings. I'm just going to hit on the part in the general section. you can read the rest on the slides. The customers, they understand that energy costs more on hot days. And so they understand that they're going to pay more during the summer, during those hot times when energy is expensive.

And they would like to see a more narrow

super-peak period. You know, they don't want to be paying super-peak prices for 12 hours a day. And I think we're kind of all on that same page. I think we're looking at, you know, offpeak, midpeak, peak, super-peak, something along that line. And the super-peak window would probably be in a three- to four-hour range.

With respect to load management and demand response, most of the customers understand that there's a need and that they would respond in a crisis when there's public pleas for conservation.

If you go back to the energy crisis we had some years back, you know, people voluntarily reduced their loads. And it lasted about two years. After that you could see that things just started ramping back up to normal usage. But when there is a crisis, people will respond.

Customers want the ability to override in demand response events. That's one of the things we factored into our programs. With our ACL program they were, when we used to run it regularly we actually allowed them one time a summer to basically override. If they're having a birthday party or something like that, they might

want to have their air conditioner on.

They're generally more receptive to temperature reset than to A/C cycling. So, in other words, if we set their thermostat back a few degrees they could live with that, rather than just turning off their air conditioner all together.

Here's SMUD's programs. It averages between like 6 and 7 percent of our total peak load. And so we have a variety of programs, the biggest one being our air conditioner cycling program, which is up to 135 megawatts if we shed the customers.

We have about 100,000 customers on that program. But with diversity and all, it's not just like a straightforward kW per customer or anything like that. We figure we get 135 megawatts. And we have done notch tests where we have verified that. So when we actually push the button, you'll see it drop right off of the system. The program works.

We have some other things, some customers on temperature-dependent rates, and curtailable contracts. We also have a voluntary curtailable, which we have used in the past. We

basically have customers signed up and we call them on a hot day and say, hey, remember we talked about this. Would you turn off your load. And there's no compensation for them other than an ad we put in the business journal at the end of every season saying thank you for your assistance.

We got a team that just recently looked at our load management/demand response offerings. And they've developed a list of recommendations. And those are going to be moving forward. They're largely contingent upon the installation of our advanced metering infrastructure.

And there's just a variety of things there. Our air conditioner load management program is over 20 years old; still uses the same old switches and radio controls that we had back then. We think there's other options that will get us the same benefit and that will kind of take us the next 20 years out.

Like I mentioned before, it's going to take us through about 2012 to implement these in conjunction with the advanced metering infrastructure installation.

Lastly, our position on the PCT. We do support it. We also support it with everyone

else. And actually when the media called us we said that we thought that it would be an enhancement to the portfolio. Basically it would give the customers additional options.

So I was kind of -- it wasn't a direct, hey, we support it where customers have no control, but we support it where customers do have control. I would like to see it go into the codes and standards, personally. And I think that's at least the starting point. I understand that there are millions and millions of homes that would not have it, but over time, you know, maybe that's the only thing they sell at Home Depot; it's the only thing you can buy as a replacement.

As utility programs go in we start installing them into the existing homes. So, I would like to see PCTs move forward.

And that's it. That was pretty quick.

PRESIDING MEMBER PFANNENSTIEL: Thanks, Jim, very good. Where do you think you're going with your rates to take advantage of the AMI? Where do you think your Board is going to be comfortable? What kind of these rate options?

MR. PARKS: They're going to go with some sort of time-of-use rate, I expect, even down

to the residential level. I think as a starting point they're a little concerned about, you know, low-income customers and life-support customers and things like that. So, they're trying to figure out how to have minimal or no impact on those customers.

And so I think they would probably start with an optional sort of rate, if we have a choice in the matter, before moving to permanent mandatory rates like that.

And we also want to do some critical peak pricing raise to test those, but I think we'll do some pilot rates and let people volunteer for those at first before we implement them on a wide scale.

PRESIDING MEMBER PFANNENSTIEL: Great, thanks. Other questions?

ASSOCIATE MEMBER ROSENFELD: I just want to say SMUD continues -- SMUD continues to amaze me with your forward attitudes. I'm very impressed.

MR. PARKS: Thank you, Art. One last comment I did want to say, too. With respect to this proceeding, some of the smaller munis are just that, they're small. And I'm just wondering

if it might be in the best interests of everybody to focus on the top five or ten. Because some of the smaller ones, it's kind of the biggest bang for the buck, I guess. So that would be my request, I guess, consider at least.

PRESIDING MEMBER PFANNENSTIEL: Thanks, Jim. Okay. I'm going to change gears a bit now. We've heard a lot about what is going on from the utilities, what they've done, what their plans are. And from both a metering and rate standpoint some of the customer contact. And then beginning discussions on enabling technologies.

We're now going to move really to a discussion of technologies, and see what's going on, what's being developed.

What I'm going to ask, however, I have a copy of Mike Gravely's slides, and there are some 60-some of them.

(Laughter.)

PRESIDING MEMBER PFANNENSTIEL: And, --

ASSOCIATE MEMBER ROSENFELD: He agreed to show only 49.

(Laughter.)

PRESIDING MEMBER PFANNENSTIEL: I'm going to request that --

MR. HUNGERFORD: We've been negotiating the length back here in the back. He's going to be trying to do this in 30 minutes.

PRESIDING MEMBER PFANNENSTIEL: Okay, because I really would like to be able to leave some time for the other members of the public who are here, and other points of view. I think that the slides -- I have had a chance to look at them, and they're pretty comprehensive. So I don't know that we need to go over each of them.

I think there's a point being we have them in front of us and there's some very interesting trends and ideas represented here. So, let's get those out, and then we'll all hear from the rest of the public.

Thank you. Mike.

MR. GRAVELY: In the interests of time we've decided just myself and Mary Ann will speak a little bit in the presentation.

In the PIER program we have initiated the Demand Response Research Center, and all the utilities that are here today are actively involved with that center.

Mary Ann Piette will talk about the demand response efforts we're doing. And then

I'll consolidate the other three areas, including storage, into it fairly quick.

There are a lot of slides here; there are a lot of pictures I can cover fairly fast. There are a couple points I'd like to discuss in the area that was discussed today about reference designs and standards, and what we're doing in the research area to help with that effort.

With that, I'll let Mary Ann speak.

MS. PIETTE: Thank you. I'm Mary Ann Piette and I'm a Staff Scientist at Lawrence Berkeley National Laboratory, and I'm with the Demand Response Research Center. I'm only going to use every other slide, so I'll try to go as fast as I can.

I'm going to try to catch us up as much as I can. I want to thank the California Energy Commission and the Public Utilities Commission for inviting me to speak today. And I hope to get you interested in the C&I, the commercial and industrial.

We've talked a lot about the residential; we've talked a lot about smart meters and home automation. But there's actually a lot we can do in the larger facilities, as well. So I

hope to get you excited and energized about what we're doing in that sector, as well.

I'm going to very quickly talk a little about the Demand Response Research Center. I'm going to be focusing on the automated demand response technology. I'll talk a little about behavior, value and tariffs. We do work in those areas, as well.

The Demand Response Research Center is in its fourth year of operation. And it's managed out of Lawrence Berkeley National Lab. And we work with many of you in the room. We do some of the work at LBNL and we do some of the work outside LBNL.

We care a lot about technologies and policies. Really we're a group that tries to understand how to do the research. To manage it, to deploy it, to collaborate with the industry to move the state forward in demand response. And we care about cost effectiveness; we care about technology. We care about energy efficiency, and I'll be trying to bring in some of the energy efficiency ideas, as well.

On the left-hand column there are some principles we've talked about throughout the day,

customer choice, automation, dynamic rates. On integrating energy efficiency and demand response we know when we go to a lot of commercial buildings that their energy use is not optimized already.

So when we try load management and DR we actually learn about do they even understand their load shape. And sometimes we find things that they can do. They say, well, can I do this every day. Sometimes they can, and then we call it retro-commissioning.

So we actually know that when you go to a building you need to look at how it's being run and how you can automate some of the strategies.

So we need procedures, and we need to understand the lighting systems, the HVAC, the controls, the thermal loads, how to use the building mass, and really how to make the buildings more dynamic.

This slide I'm just going to say that -- I'm going to talk about what auto DR is. The next slide I'm going to go into a little more detail. But primarily this is for larger facilities with centralized controls. It's not a program; it's a technology infrastructure.

And the second bullet there is what I want you to look at. This is an internet-based, two-way secure communications infrastructure. So what we're doing is we're turning demand response information, pricing information into internet signals. And I'm not going to go through all the details on the slides, but I'm going to talk about this picture for a moment.

Right now most of the price response programs are manual. So that the person gets a phone call and an email or a pager notice that today's a special day, or tomorrow's a special day. And then the building manager has to go around and flip switches and turn things off and execute something in a control system.

Now, the meter is not part of this. The meter is separate. So, when I talk about auto DR, I'm going to talk about the lighting and the controls, as an example.

What we've done is we've turned the demand response information into internet signals through something called the demand response automation server. So that's actually at a server farm.

And each of the IOUs in California has a

DR automation server. The DRAS is a continuous two-way system. Every minute the building gets a signal. The client at the building is listening -- is communicating with a control system. So the control system is pre-programmed to do something when the signals come in.

So these signals are price signals, they're modes and they're acknowledgements. So this is using this encryption authentication, just like your banking systems do, and it's secure internet systems.

Today we put this little yellow box in. And we've got dozens of these throughout the state. But many buildings don't need the little yellow box. For Target and for Walmart and for many other customers their current building can listen to internet signals using something called XML, which is kind of like html.

So we're actually taking these communication signals into software that many control systems can already host. And we're actually developing lighting control systems that can host these web services signals.

So we're using the internet. The internet is already available at many of these

buildings. This box that we have here, the box, you plug it inside the LAN and it can go and get the prices. So it goes and gets these signals.

And these buildings are listening continuously to these signals. And again, when the demand response event happens, the lighting system, the thermostat setpoints change based on choices that the owner makes to respond to the demand response. So they make those choices to execute some kind of demand response strategy.

This graphic shows you sort of where we are right now, 2008. We started this back in 2003. We did five sites. All different building types. All different control systems.

Recently we've been working with the utilities in California, with EPRI, with NIST, and with several other organizations to try to make this a standard. And as you see in the next steps, the final direction is to actually embed this in control systems in the future to move towards a national standard.

This is an open standard so that anybody could build the automation server signals; and anybody can build the client. And the client will be in the public domain, so that the information

model and the signaling infrastructure is in the public domain. That's the point, is to develop something that supports the signaling infrastructure using open technology.

And we are looking to the future of the building codes. In Title 24, 2011, to actually consider having building systems that can listen to these signals. So, if you got a Siemens or a Honeywell or a Johnson or a Lumen Energy or a Lutron system, the lighting and the control systems can listen to these signals.

And I'll make one more comment about lighting systems. We've talked a lot today about setting temperatures up, which is that's the most common thing we see is people set the temperature up when the demand response happens.

But we also have a lot of facilities that do lighting. And we believe that the dimming ballast is one of the best technologies to support daily energy efficiency and dynamic demand response.

So that's something else we want to look at in the codes in 2011, is dimming ballast systems. A dimming ballast also supports demand response summer or winter. Most of what we're

doing is summer. And we're looking at other utilities around the country of what they'll do in the winter. But lighting is an excellent technology for year-round DR capability.

The pie chart shows you a breakdown of the kinds of customers we're working with. Retail chains, commercial buildings, museums, datacenters, biotechnology. We're looking at schools, and we did some large industrials this year.

We've done critical peak pricing, demand bidding and capacity bidding. With demand bidding we do something called auto bid, auto shed. So actually the bid is in the internet server, and it gets executed when the demand bid event gets called. So we have a way of getting these different kinds of programs into these internet signals.

And you can see in 2007 we have about 25 megawatts under the auto DR with the three utilities. And we're shedding almost a third of the load. Historically we were shedding 10 to 15 percent. But this year we had some large industrials and the average is much higher. So we have a variety of customers that have been using

the technology.

This is a actual critical peak pricing event from this summer, August 30th. And one of the things I want to emphasize is that we typically are shedding load, not shifting load. We're shedding load. So we actually save energy during the demand response days.

You can see here there's about 20 megawatts under control. We're shedding about 10 percent of that. And you can see this is a six-hour event, so this is a very long event. Some of the customers only do the second three hours. So you can see a much deeper shed from three to six period.

And then no rebound. We're very careful on the control strategies to make sure that when the building goes back into the -- out of the demand response mode, there is not a new peak that occurs. If you're Target and -- then you care a lot about that because you're still operating at six. If you're an office building you might go into the nighttime mode, and without hitting a new peak.

This is the test we did for demand bid this summer with PG&E. We were at about 40

megawatts, and you can see it shed over 10 megawatts automated. Now, these industrials actually stayed off into the evening. So we had a very large shed during the August 30th test.

Very quickly, this is a graph that shows the percent shed by different program types, by different customer segments for the utilities. So we're getting very significant repeatable savings. We've gotten 10 to 15 percent over many years. We got much larger sheds this last year in some of the programs.

Now this one I want to spend a few minutes on. This is a graph showing the average percent reduction over a six-hour CPP period for about 60 sites in the PG&E service territory under automated critical peak pricing.

The red squares are the automated sites. The blue triangles are the manual ones. So, on average, what we did was we matched customer segments. So we have inland and coastal. We've got some retail, office, schools, et cetera.

The average reduction for the automated sites was 8 percent. And the average reduction for the manual sites was actually negative for this particular event.

Because sometimes the person that needs to shed is not there. We know that some fraction of the time, you could go, okay, they got -- we got the phone call. What are we supposed to do. And the guy's out sick or he's on vacation, especially in August. So, the automating it, it makes it much more repeatable and reliable. And something like critical peak pricing is something that can be automated.

This graph here shows an idea of the kind of infrastructures we're examining for automating the demand response in California. Whether it's PCTs for homes, auto DR for commercial buildings, and even auto DR for industrial.

Again, we've had a lot of luck with the industrial this year. Not every industrial customer will want to be automated, but a number of them are comfortable with the idea of the automation. It actually helps them manage their infrastructure and participate in the programs.

So I have the little yellow box there, but, again, in the future we don't want there to be a box at all. We believe that the internet signals directly to the controls is very feasible

and that's really the future of this kind of infrastructure for DR.

So, I want to emphasize that right now we have a group with the utilities, with EPRI, with NIST, with InterNex, Erich Gunther's involved, and we're actually developing the open standards for the automated demand response.

So this will be a functional specification; a set of use cases; and a data mile to support the different kinds of demand response that is going on in California. Real-time pricing, capacity bidding, critical peak pricing.

And we have a data model for using these automation for those different kinds of programs. So, again, anybody can build the automation system, and anybody can build the client. And if somebody wants to test their control system with the client, we would invite them to do so.

So, we're in the process of formalizing the automation standards. We want to look at building codes. We did do something with Title 24 this year related to what we call global temperature adjustment.

When we went to the Oakland Federal Building there were a thousand zones. And to set

the temperature up you'd have to go zone 1, zone 2, zone 3, all the way to zone 1000.

But global temperature adjustment requires from one point you set the whole building up. And that's now required in Title 24 in 2008. That if you have an energy management system, there has to be one spot where you can get to that control system. So we want to enable the commercial buildings to be able to be demand responsive.

And we also then want to look at energy management systems just like you're doing with home automation. And how do you make information for C&I customers more actionable, that they'll have better information about what they could do every day. We care about daily energy efficiency; we care about daily load management. And then DR on special days.

And really, even the C&I customers don't always understand their tariffs, nor do they necessarily minimize their peak demands. So we need to really help them understand their current load shapes and more that they can do.

One slide on behavioral research. Demand response is different than energy

efficiency because it's a continuous relationship. You know, it really requires people to be aware that they're in a DR program or their prices are changing.

So we care a lot about not just the who and what, but the why and how. And we have Karen Herter and some other folks out of Portland doing some of our research on behavior, collaborating with SMUD, looking at residential and small commercial buildings and different types of tariffs.

So there's some field tests going on this summer to explore a variety of behavioral research questions.

I have a couple slides on demand response, our rates project. Ahmad Faruqui is our lead investigator on this. And we're working with the utilities to explore a framework for characterizing DR dynamic rates.

So, we look at PTR, CPP, RTP and understand these kinds of rate designs. And work on a framework for comparing them.

So we basically look at rate design principles and how the DR is related to these different rate designs. So that's a project

that's underway and the report should be out in about a month.

This is an example of applying elasticities and the kind of DR you get out of these different types of rates. I'm not going to go through the details.

And this is my very last slide. The Demand Response Research Center is also involved in demand response value research project. Looking at the kinds of value streams for different kinds of stakeholders. And how do we understand the different frameworks for DR evaluation methodologies.

I'll stop there. Thanks.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Mary Ann. Are there questions? No. Excellent, thanks.

MR. GRAVELY: So I'll go through briefly, and mostly in picture slides, some of the other technologies in this area we're doing, both in the demand response area and in the energy storage area.

This just shows you a couple of opportunities we've worked with. DR BizNet was an opportunity that was originally generated through

PIER to look at how to manage DR, both sign-up through management, through reconciliation. And that product is actually in the commercialization process -- how to use today.

Many years ago there was questions about PCTs and thermostats and what they would cost. There was a perception it would be hundreds, maybe $400 or $500. So we actually did some research and put together a board to look at what the costs should be, what a reasonable cost would be.

And as we've heard before, the pricing is typically less than $100, and potentially less than $50 in the future for a PCT type of device.

The future of technologies, as you look at this little picture here showing you the basic elements of a PCT, or a thermostat in general, that cube today would be about the size of a sugar cube, and in the future about the size of a grain of sand.

This radio right here is 2 mm, -- fully functional radio. And that is about the size of two or three pieces of grain of sand put together. And it does function, operates. Shows you what we're doing, sort of research we're doing, is in the area of communications within the home, within

the commercial building.

When you have these small radios they don't always have as strong a signal as bigger ones. So part of the question becomes can the connectivity be there. Will they skip the signal. Can they send a signal back. And so we're doing research in that area to understand what is the criteria, how it works and how do we implement these technologies.

We're doing thing in the area of frequencies in large buildings, looking at different frequencies and different power set ratings. And so we can figure out how these things will work within a commercial building or an industrial facility, in addition to working well in residential facilities.

Now, in addition to the programs that we do, there's also a small grant program here at the Commission, Energy Innovation Small Grant Program. This is just an example of a technology that has evolved through that.

They propose new kinds of power electronics that can be used, for example, in supporting a wind system at a residential site or commercial site. This particular case they

brought their concept for it and approved it in the small grant program.

And then under our industrial program we're actually out doing a demonstration. This expects to have a substantial reduction in cost. And handles -- active harmonic filter, so it handles harmonics that are generated, for example, in wind systems when they're variable speed. But just an example of a new technology and methods the PIER program has for companies and for universities to bring new programs to the forefront and get them demonstrated.

Erich Gunther was going to present this. These charts will be posted on the website, as will our contact information. So if you have specific questions, either later today or after today, feel free to call either of us and we can answer those questions.

So, questions this morning were mentioned about how do we get these technologies worked, codes, standards and reference the designs.

One technology we use a lot, or one reference we do is a reference design here. And what happens is you get together with industry and

you develop a technical blueprint of the device. And these reference designs are an iterative process. We actually have reference design, for example, for the PCT as part of our standards. But a reference design helps the industry guides work.

A lot of the questions we get from the industry side is you have lots of people out there that want to do thing, and they need direction. As you mentioned before, they don't want to build a hundred different products and only one or two make it. They'd like to build products that will make it in a commercial market.

We'd like to be able to keep competition open so we look for areas where we can help define things in a manner that there is competition, but also the fact that it works the way we need it to work. So, this device, this design helps that process work.

Here's some examples from the past of successful reference designs that were used by industry and regulators to make it work. And, of course, what people are seeing, the thumb-drive has rapidly progressed in the industry today. As a result of this reference design process they

were able to get things together, get it working and get it out in the field much faster than if they had not had that process in place.

The benefits of the reference design. Facilitates the communications. And I think that's an area where we have found in the PIER program and the research program that we can provide a lot, even though we're part of the regulatory arm, is that we bring people together and we help them communicate and we help them resolve things.

We're not trying to dictate what happens, but what we do try and do is help them get through that area of a new product that's been developed and get them in a commercial market.

This was just another example showing how the cable modem environment worked. And, again, that information is available and we can discuss it later if anybody has any questions.

The last thing I'll mention before I get into storage is this morning's discussion there are a couple efforts we have right now to help in this area of communications design. John mentioned the different working groups.

We're actively involved in an

infrastructure working group. And for that case, for example, how you communicate with the version one, version two software. You have a baseline; you have that software and you have a system you want to communicate.

We want to bring in more DR and we want to help the people that want to participate and know how to participate. There are things like rules for participating loads. And so we don't want someone to run around and build a product that's built on 50 Hertz when the world's on 60 Hertz. So we don't want to build a product that's built on a modem that you would use in the old days, a dial-up modem, when the rest of the world is operating on DSL. So, what we're trying to do is define the information to help it work that way.

The other thing that we're doing here in the program, again for Commissioner Chong, is we're working smart grids in California. That's become a great big issue. I think smart is right next to green now, everybody's got smart next to their name.

We're actually meeting with your staff on the 14th of March to actually decide what we

think a smart grid in California should look like. One of the key elements, you know, where should the Commissions be, where should we stay out of. Those types of questions. And how do we help industry. We're having an industry meeting on the 13th to ask those same kind of questions. How do we help the process without hindering the process. How do we encourage competition to avoid having latent systems or systems that don't operate in the future or are obsolete in a couple years.

With that I'll transition to the storage piece, which is also part of the workshop here today. Briefly, again, for questions I'll take them all at the end.

So, in the cases here you can see the discussion, but in storage you can store energy at night, and you can discharge it during the day, so philosophically if you have enough storage you can make this into a much more level diagram.

We don't currently have a lot of storage pricing. The price is very high at times. People want to sell energy then, and then they want to store it when it's down low.

This just gives you a collage of the type of storage devices that are available;

hundreds of megawatts. And there are devices that are tens of kilowatts, or down into one range. This just shows you different ones that we've worked with over the years.

We currently have an active project with these different technologies. I'll show you a couple pictures as we go through and you may hear from some of the vendors that are in this market today.

Ultra-capacitors. We're doing a project with SMUD right now where we're using ultra-capacitor energy to store the trains when they slow down. They put energy back on the track. We store it in the batteries, or the ultracaps. And then when it accelerates it puts it back into the track again. One, it provides efficiency. Two, it provides grid stability.

We've done work with flywheel technology with the ISO. We did a demonstration here using flywheels for frequency response for grid stability. And we actually -- the big effort was on the lower left here, the communications.

The majority of the effort was in the communicating between the device and the ISO so the device knew what to do, and the ISO knew what

it did do. And so we're using the same architecture now and two other projects in the future, because we've worked out all the logistics with the ISO part. Because visibility from the ISO is important as much as it is the control system that tells them how to do it.

Mobile technology, whether it's fire, flood, drought, power needs change. One of the things we're looking at, each of these trailers, we have two of them right now in the test program. Each one is 500 kilowatts for an hour, which is a substantial amount of energy. And we move that around. We think we can find the ability.

These things can be set up in a matter of hours or a matter of days. And we try to assess, first of all, do they work. And second of all, how well they work and how cost effective they are.

As you saw in the legislation, the two areas that we spend a lot of time on is one is validate the technology works and it's feasible. And the second area is what's the cost effectiveness of it.

We have a project right now with SMUD looking at VRV technology where we're putting in a

datacenter and we're using it nine hours of storage; we use the peak reduction every day. And it's the potential of using the same storage to eliminate the need for backup generation.

One of our utilities is considering a large sodium sulfur battery system of over 40 megawatts. And we're working with them to help do their validation of the performance, and also the validation of the economics of those projects over the future.

This chart just shows you, any of these numbers, I've been in this industry about 15 years, any day, any chart has a different price, but it gives you a relative basis. And that is one of the reasons we don't have a lot of storage today is it's expensive. And so one of the questions becomes what's the value and how are you going to pay for it. And that's what we get down through now, different projects, different applications.

There's a quick chart here just to show you how, in the case of thermal storage, the thermal storage has probably done the most in the area of rates today, in the area of shifting the peak to offpeak and making it more level. To look

at the ability of storing it in the nighttime and having it available during the day.

And also looking at the fact that when you use offpeak charging and onpeak storage you actually have not only a peak load shifting, but you can have an efficiency improvement and you can definitely have a greenhouse gas reduction.

Very quick, questions at all?

PRESIDING MEMBER PFANNENSTIEL: Questions? That was fast.

(Laughter.)

PRESIDING MEMBER PFANNENSTIEL: Okay, thank you. Good slides, also. Go back to them.

Okay, now we have -- I have a number of blue cards from people who have asked to speak. And I'll go through them in essentially the order they were given to me.

I would ask that people be respectful of the fact that there are a lot of people here and many of whom would like to speak. So, please, this isn't the opportunity, as I said before, for a sales pitch of your specific product.

We're very interested in knowing what's out there, what your concerns are, whether you represent a specific product or consumer groups or

whomever. You know, I would like to hear from as many people here as possible.

Let's start with Tim Simon from Golden Power.

(Pause.)

PRESIDING MEMBER PFANNENSTIEL: The same request of those who are making slide presentations holds in terms of being respectful of other people. Thank you.

MR. SIMON: It's my only slide. My name is Tim Simon. Thank you for hearing from me. As I've sat here throughout the day I've heard several times about PCTs and Home Depot.

Just so you understand, my company, Golden Power, is the largest supplier of thermostats to Home Depot, and has been for probably about ten years. We also have significant market in thermostats in other areas, but that one name keeps coming up.

When we've looked at PCTs over the last few years our idea has been that the PCT is not a technology. It is a way of incorporating the technology. The thermostat, itself, is a fairly simple product. And so we've looked at how we can take our ideas to be able to enable virtually any

of the technologies you may be looking at.

For example, our thermostat works with ZigBee, with ZWay, with 6-LoPan (phonetic), with PowerLine carrier. So it works with virtually anything, I think, that the utilities or anybody else will decide they want to use.

The other part of our thermostat is that it is designed to be a gateway into the home for other devices. So, the customer could buy this product even if he wasn't yet connecting to a utility. His only concern would be that ultimately it would be able to connect to the utility. So there has to be some basic standards here.

That's why, from our standpoint, we have supported the Title 24 PCT concept because it gives us the basic fundamentals we need. I don't need the technology described, but I need the basics described.

And because Title 24 has been talked about for some time, it is probably the absolute most common question I have when our customers come to us and say where do we stand with the PCT. It almost always is where do we stand with the PCT vis-a-vis Title 24 and the State of California.

Their fear is that if we move forward until that is decided that Title 24 ultimately could undermine them if it takes a different turn than we're at with our own technology.

Where we stand right now is we have had a product that's been prepared to be on the shelf for Home Depot for probably six months now. And we're waiting just to know where everybody's going.

As I said, we're very versed in radio. ZigBee, Z-wave, 6-LoPan, Power Line Carrier and so forth. And our thermostat has modules that fit in the back of it that allow the user ultimately to slide into that, so that if one utility picks ZigBee, the ZigBee radio could slide in. If another picked 6-LoPan, the 6-LoPan radio could slide in.

It also allows you or the consumer to use multiple radios, or not necessarily radios, but communications devices. So a consumer could say my local utility has selected ZigBee, so I have that ZigBee module that slides in.

But, myself, I happen to have, as Erich Gunther does, a Z-Wave system in his house. So he says, well, why do I have to get rid of the Z-Wave

system because my utility has picked ZigBee.

Well, in our case he doesn't have to. We can accept four different types of communication devices.

So the consumer who already has a home automation system, can continue with his thermostat and then still add the communicating device to the utility.

So, from our standpoint we look and say, there's a good, better, best concept we think customers will like. Some customers will want a very simple thermostat, as basic as can be, to keep the price down. Others will pick something with more features and some people will pick the one with most features.

The one that we see over here, if you'll notice, in the upper left-hand corner, this shows what their current utility rate is, how much per kilowatt hour. In the upper right-hand corner it tells them the day and the date. The little symbol that some people keep saying is the radiation symbol, but, no, it's not. It's the fan. The radiation symbol has three blades. Shows that the fan's moving.

In the left-hand side ratio link shows

which radios or communication devices are talking. The temperature; the target temperature. The humidity, which is a really big feature.

And for years, many of our thermostats incorporate humidity. And you can set the humidity and say I don't care about the temperature. This is particularly useful in areas like Florida with high humidity. I don't care what the temperature is, I'm going back to New York. But I want to know that when the humidity hits a certain point it will turn on the air conditioner to dehumidify. Or you can turn on a separate dehumidifying device other than the air conditioner to dehumidify.

And then down at the bottom it has a crawl screen where the utility could send messages to. Whether you're going to have a maintenance power outage tomorrow from 1:00 to 2:00; or there's a crisis event. Here's what you're paying. Blackout possible. Reduce load, and so forth.

So our goal has been to have a product available which has the basic technology of a thermostat and the ability to accept virtually any technology that any of the entrepreneurs in the

Silicon Valley or anybody else who's going to come and say, this could do well in a thermostat. That our thermostat is ready, willing and able to accept that technology, accept it quickly and make it work with it.

And from our standpoint the biggest thing that we need is some basics, knowing that what ultimately will be decided will be the same through as wide area as possible.

Let me finish by saying that if the state picks some basic standards, it is enormously advantage to us. Because someone like Home Depot looks and says, I can carry this product in a state, and define it by a state fairly easy.

If I'm defining it by utility district, it becomes near impossible. For Home Depot to say this product should be on the shelves in Southern California Edison's territory is almost inconceivable for them to figure out how to do that.

But if we say this is the thermostat that should be on the shelf in California, it's very easy, and they'll move quickly to do that.

And then you have Southern California Edison picked one communication technology, PG&E

picks another, SMUD picks another, doesn't matter. Different module slides in the back of it. But the thermostat that's carried by the retailer would be universal.

Questions?

PRESIDING MEMBER PFANNENSTIEL: Thank you. Next card is from Charles Toca from URB Power Systems.

(Pause.)

MR. TOCA: Thank you very much. My name's Charles Toca; I'm a Sales Affiliate with VRV Power Systems. Also have my own company called US&R Power Group Partners. I appreciate the Commission taking the time to talk about advanced energy storage for demand response.

The Electricity Storage Association is comprised of many energy storage companies. They have identified the different technologies according to their value, and according to what they bring to the market.

There are at least, looking here, about five technologies that bring energy as a part of their main component to the market. These, I think, are great technologies for energy demand response.

Cal-ISO has some opinions about energy storage and the value of it. I think one of the main issues that Cal-ISO has identified is that it's not the technology that's the issue as far as deployment, but the absence of market mechanisms that recognize the value of the storage facilities; and financially compensate the owners for the services and benefits they can provide.

This is an example of a 6 megawatt facility at a windfarm. Also an example of a distributed energy resource, distributed advanced energy storage system at the Santa Rita Jail. This is a study that has been done. I didn't do the study, myself. One of the people at VRV has done it.

But one of the things they discovered was that by combining solar plus energy storage they were able to reduce the demand by quite a bit in the afternoon. The yellow line, the yellow spot is the actual power being brought through the meter from PG&E. As you can tell, it's totally wiped out the spikiness that occurs. Very very flat load from PG&E meter.

I think a key thing I would like to get across to the Commission is to be very open to the

idea of advanced energy storage. Many different kinds of advanced energy storage technologies out there, not just the VRV technology. Although I think it's very good. But there's many different applications for it.

For example, distributed resource facility at Alameda. Consider a large, 5 megawatt system at an industrial site. You could have increased demand response without interruption after the industrial has done everything they can to be responsive with demand response controls and that sort of thing.

This is sort of the last mile. This would allow for dispatchability by Cal-ISO. It would require an emergency in order to get this done. Potentially could have 1700 megawatts of demand that they could use on a daily basis for grid reliability. It could provide permanent load shift. It also provides uninterruptible power supply to the customer, the host customer, and emergency power.

And I'm saying these, I'm mentioning these obviously because I don't think it's necessary for the California Energy Commission to say, gee, we have to find some kind of system that

only compensates, or only incentivizes energy storage for demand response.

I think that it would be very useful if you would look at many different values advanced energy storage can provide. And demand response could be the one extra thing that then allows this to be commercial and be deployable.

We include local grid support. This is an advantage to the utility, providing reactive power and power conditioning. And it can defer generation and transmission. I think most members of the Commission are familiar with all the benefits of advanced energy storage. I'm just suggesting that you look at the many different values and see how you can encourage that demand response, as well.

Again, we recommend that the Commission evaluate advanced energy storage solutions. We suggest a workshop after this, looking at the different kinds of advanced energy storage and different ways it can be used to obtain load management. And to value multiple benefits of AES beyond just peak shaving.

Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank

you, Mr. Toca. Questions?

ASSOCIATE MEMBER ROSENFELD: Do you want to say a few words about the relative costs of storage versus demand response by controlling your air conditioner, for example, or your pool pump.

MR. TOCA: From my perspective, looking at the energy storage systems, the battery systems, I think that energy storage today is really expensive if you're only using it just for demand response. We have not been able to find a way to make it economic for that purpose.

What we envision is a situation where a customer may say I have a value for UPS, I have a value for emergency backup, I want to reduce my carbon footprint, I don't want to have a diesel generator onsite for emergency backup. I want to provide services to Cal-ISO, I want to provide services to my utility by improving the power condition quality on the local grid.

But I just can't make it economically. Oh, gee, demand response. Maybe there's a way here to be responsive to price signals and that sort of thing. And it becomes an entire package that makes the product work.

Does that make sense?

ASSOCIATE MEMBER ROSENFELD: Yeah. I guess I'm so obsessed with the idea of doing thermal storage first, that -- more power to you on your working on a good thing. But it seems to be a little lower on my priority list.

MR. TOCA: My only suggestion would be that after all these other items are taken a look at and reviewed, that energy storage, advanced energy storage is sort of like the final mile. You know, once the customer has done thermal storage and the controls and that sort of thing, I can take their entire system off the grid with energy storage.

And the question is, you know, what's the advantage and what's the benefit, and can we make it economic. I think there's ways to do that. I suggest a workshop to look at ways that the other are being looked at for demand response, could also be applied to energy storage.

ASSOCIATE MEMBER ROSENFELD: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you.

MR. BERBERICH: Chairman, just a question. Perhaps, Mr. Toca. Would not the -- the storage wouldn't be able to participate. I

noted you attributed something to the California ISO there, but power producers would be able to participate in the ancillary services and in the energy markets and the ISO markets, would they not?

MR. TOCA: Yes.

MR. BERBERICH: So that would be a revenue source, as opposed to just the storage, itself, wouldn't it?

MR. TOCA: Yes, we're looking at partnering with generators to take their output, allowing them to generate on an even rate, staying efficient, and by being efficient, reduce their emissions. Then using the energy storage to charge and discharge and provide the pulse to the Cal-ISO for regulation.

We can do that in conjunction with a generator. We can also do that in conjunction with a energy user.

MR. BERBERICH: The point I wanted to make was that there are revenue streams that could come through the marketplace to folks like yourselves.

MR. TOCA: Right. And ideally we would do that at a commercial/industrial customer. And

then if the utility needs a demand response, we can provide that, as well.

MR. BERBERICH: Thanks.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Mr. Toca.

MR. TOCA: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Helmut Blum from ERS.

MR. BLUM: My name is Helmut Blum and I'm --

PRESIDING MEMBER PFANNENSTIEL: Mr. Blum, please speak into the microphone, otherwise you won't get picked up for those who are on the phone.

MR. BLUM: My name is Helmut Blum. Is that better to hear?

COMMISSIONER BYRON: That microphone is for the recorder. The other microphone is the one you need to speak into.

MR. BLUM: So in the meantime everybody knows my name.

(Laughter.)

MR. BLUM: I have a company, we are right now 20 people on 13,000 square feet. We're producing rolling shutters, solar screens and

retractable awnings.

Just to explain a little bit, I don't know if he can get this going. But like you note on the RV we have these things we can run out, retractable awnings. Ours, on the RV they swing like this around that pivot point. The retractable awning goes like this, so you have no post. Maximum you can do is 13 feet out and nonlimit, which you have to enter it -- can you run it?

MR. HUNGERFORD: Which one do you want? The whole thing? That way?

MR. BLUM: Yeah. Is it louder?

MR. HUNGERFORD: I've got it up all the way.

MR. BLUM: I have to sing, then?

MR. HUNGERFORD: Yeah, I'm afraid so.

(Pause.)

(Playing video.)

MR. HUNGERFORD: Can you guys hear that?

MR. BLUM: So you see solar screens going up and down. Retractable awning going in and out. That's a view from the inside. It's a fairly small one.

There's a rolling shutter. See you see

little holes -- they are closed once you hit the button and un -- completely.

This demonstrate outside sun coming, blocked on the outside, blocked on the inside. See now nothing, no UV light, no IR hits the windows. If you have nothing there the interior shading, then you'll see the whole heat starts on the interior shading, you know, and runs up and circles, and (inaudible), as well. Which is not loud, but -- 71 degrees. And if I don't shade it, if I shade it then it goes far below.

This shows now the production of a retractable awning. Here you can see how good performance looks.

We do it now 20 years, so over 5000 customers. We get the complaint over 90 percent, why did we not know about you earlier.

Can you shut it off?

MR. HUNGERFORD: Um-hum.

MR. BLUM: What the theory is behind it, very simple. You know there are high sophisticated mathematical calculation, but every house in California has about 50 degrees in the morning in the winter and the summertime.

And we know also Europe, as well here,

that the interior heat gets influenced by the energy of the solar heat gain, solar windows. The rest is visibility.

So if you now look at it and say, okay, 50 and we start at 50, I mean 50 percent through the windows, so we start at 50. But I, in the practice, found out over the 20 years no matter what the outside temperature is, 110, 120, inside in a house you never see more than 90 plus/minus.

That means we get a solar heat gain from 50 up to 90 max. The human body starts to suffer from let's say 80 degrees on. So, theoretically we're dealing here just with 10 degrees which is unbearable. So, from 80 to 90.

Exterior shading has a potential to reduce the inhouse temperature 10 to 40 degrees. That means that it's a piece of cake to bring the 10 degrees down just with a partially coverage of the windows; mostly only the windows where the sun hits right now.

The whole trick is, and you know it, I have test runs, that the heat which applies to the house is basically the UV light and the IR light. You can check it on your car. If you go touch the windows, the window's warm. That's the IR light,

which is stopped by the glass. And the heat is now conveyed into the car.

In the car there's a shortwave UV light which is the majority, something in the vicinity of 90 percent, gets in the car; heats all -- devices, converts into heat and this heat is now a long wave which glass stops. The same thing we have on a house.

So I know now by expertise, and you can come and say, okay, we have to check it, that calculator, do whatever I know where I install exterior shading devices achieving very much the heat off the glass. The people have the control of the interior without usage of air conditioning.

In the wintertime I realize that I can keep about 5 degrees temperature in the house if I let the shutters down at daytime before the cold starts.

Thank you. Any questions?

PRESIDING MEMBER PFANNENSTIEL: Thank you, Mr. Blum.

ASSOCIATE MEMBER ROSENFELD: Mr. Blum, I'm basically prejudiced towards shutters. I spent ten years in Cairo where everybody around the Mediterranean has shutters.

But it seems to me more of an energy efficiency issue. I'm wondering what the reaction of the utilities would be to give incentives for shutters under the energy efficiency programs. I don't see it primarily as a load management issue.

MR. BLUM: No, you see incentives fine, but that's not what I'm looking for. My problem is, you know, that here about 60, 70 percent of the houses are built in -- communities. And these communities, you know, they are very reluctant to allow a customer, even if he wants them desperately, to put something on the outside.

We have cases, we had one in Nevada from another company, and they have now a bill 100 which says, okay, that if somebody wants to put up exterior shading for the purpose of energy conservation or security, that it cannot be denied. But it has somehow to meet a little bit the other environment, you know.

That's what I heard from the Senator there that he has to go and tie it a little bit more, because the association tried to sneak out on this little window there.

And then, you know, it is very much you try it. Call PG&E and ask them about rolling

shutters. Never heard of it.

You know what is in Europe is worldwide known. Let me just add, just for maybe here and there somebody might be interested, there is a thing like millions, you can almost say, like 200,000 to 500,000 retractable awnings are sold in each of the major European countries.

And I had a question here, it was basically an editor from a magazine. And she wrote down due to the fact that the energy costs are three to four times higher, that's the reason why so many more awnings are sold there. Here we sold last year I think some 70,000, all in America.

And she was surprised when I said that's wrong. Wrong. Was a retractable awning, how do you want to save in Europe energy only by saving on cooling costs. That means air conditioning. We have no air conditioning in Europe, maybe here and there. No air conditioning.

The other thing is on the rolling shutter you can say, you ask and say how much do you save a year on energy, I mean cooling costs out, you know, but what does it do, you know. What does it save you on energy. In summertime

when it's so hot, nothing. They do not use rolling shutters for keeping the sun out. They only get 30 sunny days if they are lucky.

But here we're looking at 300. Here is the sun, where we say; other there is the wintertime. You save oil. If I forgot in the wintertime put my shutters down, I mean, not the whole time, but significantly that has effect on my oil consumption.

ASSOCIATE MEMBER ROSENFELD: I think if there's a Nevada bill which is doing you some good, you should find a legislator here who will help you equally. I think you have a good idea, but we've probably spent enough time on it now.

MR. BLUM: Yes. We had a lot of communication. I'm now going -- my Senator is Joe Simitian. We have already approached him. Let's see what we can do that way, you know.

I'm just happy that you hear about it and that I have the opportunity. This is a new product, you know, I cannot blame it on you, you don't know nothing about it because I do not have money enough to make PR yet.

Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank

you. Rick Counihan, EnerNOC.

MR. COUNIHAN: Thank you for giving me the opportunity to speak with you this afternoon. I just wanted, in the context of the discussion of demand response today, I just wanted to talk briefly to remind you about the role that aggregators can play. And I won't do an advertisement, Commissioner Pfannenstiel.

But I think it's important to keep that role in mind as we go forward with the various load management standards in various proceedings at both Commissioners.

So, just briefly, demand response aggregators aggregate commercial and industrial customers into blocks. And then when the ISO or the utility calls, we turn down their energy use.

And the programs that we and our competitors run here in California offer a lot of flexibility. And I just want to point to two aspects of that, because we've been talking about a lot of distinctions today, day-ahead, day-of, energy programs, emergency programs.

But the programs that we at EnerNOC and our competitors provide, provide a lot of flexibility because they can be called day-ahead

or day-of. Many of them can be called on 30 minutes notice.

And so the distinction between a price-responsive program and an emergency program can be blurred here because these programs have so much flexibility. And so sometimes that distinction no longer makes -- is not as relevant.

A couple of things that we bring to the table as aggregators to help California meet its demand response goals: We have specialized staff with specialized knowledge to help customers identify the opportunities in their facilities to save energy on peak days.

Not every customer knows what they can do. Most of them, when we initially approach them, say all our energy use is necessary. There's nothing we can do on a hot day. But if you work with them you can find those things.

We also have the ability to customize contracts for customers. Utilities have to offer tariffs that are the same for everyone. We have the ability to customize and meet the customers' needs.

We do auto DR at EnerNOC. Many of our competitors, as well, automate the demand response

like in the way that Mary Ann Piette showed you here. We have existing infrastructures, control rooms, communications pathways. And all these assets can be brought to bear to help California meet its demand response needs.

So, my concern to the policymakers, to you, is that as we go forward that the role of aggregators be considered and not be excluded. And I have just a couple of examples from the last couple of years where the role of aggregators perhaps is not considered. Not necessarily for bad reasons, but just not considered.

The auto DR program that Mary Ann described earlier, great program. The DR RC has done a lot of good work. And yet in certain utility areas, certain utility service territories, aggregators and their demand response programs are not allowed to participate. Even though we do auto DR, some aspects of auto DR already.

Recently, the CPUC passed a critical peak pricing tariff for San Diego Gas and Electric. Good idea. But really, the impact that would have on dispatchable programs was not necessarily worked out in advance.

And so we had some conversations with San Diego Gas and Electric; and I think my belief is that a good resolution has come up. But it just wasn't thought about beforehand. And the example is if the customer is defaulted into a certain tariff and then they can't participate in other demand response programs, what does that mean. And so I think we've worked through it with San Diego Gas and Electric, but it's just another example.

So, I'll stop there on my examples, but I'd just like to make just a couple of requests. The first is, as we go forward with this proceeding and others, don't forget that aggregators can help California meet its goals. Try to take us into account. And I undoubtedly will remind you to do so.

Second, I think the emphasis on open architectures reference designs is really a good place for the Energy Commission to be. I support what Mike Gravely and Erich Gunther have been doing and talking about. That allows everybody to participate; to use the same communications technologies. Proprietary technologies block out certain competitors. So I support that.

And I wouldn't be Rick Counihan if I didn't bring up the fact that California needs to improve its baseline methodologies for calculating the impact of demand response. The baselines that are generally in use here in California are less accurate than they could be. Research at the Demand Response Research Center has demonstrated that. Other studies have demonstrated that.

And I look forward to working with you to make those better in the future. And I'll stop there. Thank you very much.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Rick. Rick Boland, e-Radio USA.

MR. BOLAND: Good afternoon, and thank you for allowing me to address you.

We've heard a lot of discussion today about the PCT. We've heard a lot of discussion today about enabling technologies, both through the meter and in the PCT.

I'm here to just reiterate several points about using RDS, or radio data systems, for a simple one-way reliable and low-cost method to deliver demand response.

The PCT standard that was adopted and proposed by the Energy Commission included a RDS

technology inside the PCT for sending messages and controls. And these messages not only can be sent in times of pricing activity or emergency activity, but also messages can be delivered by RDS when there are blackout conditions occurring.

Several other points I'd like to make just for consideration of the record are that RDS is a very long-lasting and stable technology using existing FM radio infrastructure.

And the other important factor that was discussed today are open standards. And RDS is an open, global standard that is used by broadcasters to send data to a wide variety of devices, particularly in the automotive infrastructure. And it also can be expanded to be used in other devices and appliances.

So the PCT is a starting point. There are inhome displays at the moment. There are devices in your car that are receiving RDS. So it is a very ubiquitous technology.

Another factor that I'd like to bring up is that there is no internet connection on the cost of the installation and complexity of an installation of an internet or home network required. This, again, is a simple one-way

communication from a radio transmitter to a receiver device. Think of a PCT.

The way the Title 24 standards were developed for the PCT, the messaging methodology would support both pricing programs, utility messages to customers. It will also allow the remote adjustment through RDS of a PCT. And allows for the customer override of the adjustment setting.

Lastly, two other features that were very important as the standards were being developed, were the ability to send secure and encrypted messages, which RDS supports. And the ability to service large population centers economically, as well as reach remote areas.

The calculations were made to cover the State of California you'd need about 33 radio stations networked together to cover the entire state, about 99 percent of the state. And you also can deliver messages targeted to substation zip code and other granular measures.

And then lastly, the thermostat, the PCT that was designed under the Title 24 standard was designed, in part, to be able to be purchased by the consumer at a retail outlet, and installed by

a consumer. And RDS is very supportive of that technology. It's essentially plug-and-play technology.

And we'd like to go on the record, our company, e-Radio, that we're very supportive of all the work that the Energy Commission has done, the PIER program has done in validating RDS; and we hope for a continuance of this program in the future.

I'll take questions.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Mr. Boland. Greg Tropsa, ICE Energy.

MR. TROPSA: Tropsa.

PRESIDING MEMBER PFANNENSTIEL: Tropsa.

MR. TROPSA: Thank you. My name's Greg Tropsa with ICE Energy, and I'm here today to speak today in support of end-use storage systems. My hope is that through the scoping of the workshop process that we can evaluate more about permanent load-shifting technologies and building specifically end-use storage systems.

And I'm speaking today specifically about building end-use storage, as opposed to central storage or large compressed storage. So my comments --

PRESIDING MEMBER PFANNENSTIEL: And, Mr. Tropsa, I should point out we do have copies of your slides.

MR. TROPSA: Thank you very much.

PRESIDING MEMBER PFANNENSTIEL: They're fairly extensive, and so I would encourage you --

MR. TROPSA: Move quickly.

PRESIDING MEMBER PFANNENSTIEL: -- to just hit upon the key points --

MR. TROPSA: I will.

PRESIDING MEMBER PFANNENSTIEL: -- in them. Thank you.

MR. TROPSA: Okay. So as we've learned today, thermally driven air conditioning load is the root cause of California's summer peak demand problem. And load management, using distributed, highly distributed energy storage, is a persistent solution to the problem.

It is a form, if you think about it, of A/C control. But it's used 225 days of the year, six hours a day. And I want to show a quick case to you where I believe that the demand reduction counts as demand response or demand resource; and the load shifting is an efficiency measure and achieves many of the goals.

So, we think it's the right time for storage. And we encourage the CEC to exercise its authority to adopt load management standards.

I want to focus on the elements of the time and locational TDV energy efficiency metric that's part of the title 24 building standards and using that as a measure to determine whether or not a building end-use storage device is efficient.

Efficiency is an important goal of the Commission and it has been, in terms of historical proceedings. And I don't want to lose sight of efficiency for building end use.

We're recommending that you consider codifying energy storage in utility integrated resource plans. And that the state quantify the environmental benefits of storage in support of the state's greenhouse gas reduction goals.

There are significant benefits for storing thermally driven load and using the offpeak excess wind power during the night similarly, as we heard with building-integrated PV. As the building PV starts to fall off the thermal gain creates a load for the air conditioning. So building PV, plus ice and then

store that energy at night using wind is the perfect solution for California.

In two states, Connecticut and Hawaii, ice storage is considered a renewable energy resource. So you might consider how this fits into your renewable energy resource plans. Everybody's trying to find ways to achieve those goals.

I think the benefits of the load shifting should be able to be counted towards the IOUs' energy efficiency goals. And similarly, the demand response towards their DR goals.

And I would encourage the Commission and the PUC, particularly, to look at allowing the utilities to expense investments that they make in qualifying energy storage resources in the year that those investments are made.

Quick attention to site energy. Site energy is a very useful metric for efficiency, simple to understand, it's easy to measure. But in itself, it doesn't directly create value.

We look at it to reduce fuel consumption, emissions, improve T&D constraints, especially important when onpeak, and to save money. But the above four factors are how value

is created.

So if we take a look at a building end-use efficiency measure, improving the efficiency of an air conditioning system from its average efficiency of 10 to 12, using the avoided cost model that was developed by the PUC, we find that we reduce 20 mBtus of fuel, associated emissions; we have a peak reduction and a tariff savings.

Maintaining the same efficiency of the air conditioner and shifting its load to offpeak, we get a 3X improvement of fuel, a 2X improvement in CO2, a 5X improvement in peak demand reduction and a 3X improvement in cost.

So then the conclusion here is that if you look at the TDV metric, which is the one I described earlier on, it does mirror the avoided cost calculation that's used in the energy efficiency program.

And if you look at the high-efficiency air conditioner, you get a TDV savings of 42. Shifting the load you get a TDV savings of 107. About two and a half times. So, it correlates.

More importantly, if you only look at building end-use efficiency, to equate the two you'd have to have an air conditioner that has an

energy efficiency ratio of 19 to match those benefits.

So, load management, shifting load, can be an efficiency measure, peak demand reduction can be and is a firm energy resource for the grid.

We also took a look at your levelized cost comparison of central generation. And we employed E-3, Brian Hoary (phonetic), to take a look at these numbers. And what we did is we created a 20-year power purchase agreement for a large distributed 100-megawatt energy storage plant, thermal storage distributed on buildings.

What I wanted to show you here to speak to the issue of cost effectiveness, that when you consider the energy to create the storage at night, the cost of the energy, the cost of the capacity installing it, and not asking the customer to participate, including the finance cost, this is where that lands on your chart with respect to the other resources that you have listed in that levelized cost analysis.

And that's it. Any questions?

PRESIDING MEMBER PFANNENSTIEL: Thank you. Questions? Commissioner Rosenfeld.

ASSOCIATE MEMBER ROSENFELD: Yeah, Greg,

I feel a little bit the way I did with Mr. Blum. You've got an obviously good technology there. And insofar as critical peak pricing comes in or even peak time rebates come in, you should be extremely cost effective. So it's not quite clear to me what you want us to do. What's the catch here?

MR. TROPSA: The catch is the benefit of the resource enures to the system to all ratepayers. Asking commercial customers to invest and to study and to bet on tariffs being consistent or persistent is very difficult.

So, if you hope to transform the market to have storage enter the market in a large way, exercising your load management authority, codifying it in the resource plans for the utility can help to move the market forward.

ASSOCIATE MEMBER ROSENFELD: And I ask you the same question I asked Mr. Blum, though. Will the utilities -- if using time-dependent valuation you come out with all these marvelous numbers, why don't the utilities give incentives for your product?

MR. TROPSA: Well, recently we concluded a proceeding with the PUC. Commissioner Chong

presided over that proceeding. And we did find that permanent load shifting, which is the code word for ice energy storage, to be cost effective and in the best interests of the ratepayers.

And the IOUs were ordered to request for proposals. And I'm pleased to announce that there have been several that have been awarded by PG&E and Southern California Edison. And, in fact, San Diego Gas and Electric is doing more studies, and many of the municipal utilities are.

So, it is starting to move into the state.

ASSOCIATE MEMBER ROSENFELD: Thanks.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Mike Heinrich from EPRI.

I might say we're in our last hour and I have a dozen or so speakers left. So, we need to be cognizant of that.

MR. HEINRICH: Yes, thank you very much. I'll be very brief. I just want to actually echo some of Mike Gravely's comments on energy storage really as a tool for load management, and a large tool.

We heard about this morning from edf they've used energy storage in the pump storage

area. We've done the same thing in the State of California. But, building another pump storage facility is going to be probably very difficult.

I don't think we want to end up -- we all know we're going to go with more renewables. We don't want to end up like the State of Texas did last week with load management by emergency, a stage two emergency. Although it's an effective method of load management, I don't think it's optimal.

So, as we've seen the shaving of the peak through some sort of storage, and I'm not going to propose -- I'm not a proponent of any one type of energy storage. We've heard about some. I'll talk about a few others. But the fact is, it's a very effective tool for load management.

You've seen all these different types of load management. Some of them can be used for load leveling, ramping, frequency regulation. But a focus, the high priority, I think, in the phase for load management in the State of California is we need more study and analysis for those areas on the upper right-hand corner where we can get more load management out of our energy storage.

This is a very simple diagram. It

really shows what it's all about. Essentially you're creating a storage buffer, a shock absorber, if you will, for things like wind and other renewables.

The key is, and this is a -- we're moving forward in a time much like Edison when he invented the light bulb. He didn't do it by evolution, he did it with a revolution. And that means a great deal of study so we get it right.

And that's the end of my comments. Any questions?

PRESIDING MEMBER PFANNENSTIEL: Thank you, sir. No questions. Gayatri Schilberg for TURN.

MS. SCHILBERG: Good afternoon. I'm Gayatri Schilberg with JBS Energy representing TURN, The Utility Reform Network.

I just had a few comments that I'd like to address toward the issue of scope of this proceeding. And specifically I'm looking at the notice of this workshop and the bullet points on, I guess it would be page 2, that talk about the different aspects that are going to be considered in this proceeding.

So, TURN's first suggestion is that the

second bullet, electricity rate design, not be considered in this proceeding. It's already being thoroughly reviewed at the Public Utilities Commission. Ultimately they're the ones that need to decide on it.

Now we find that LBNL is also studying a lot of rate design issues. So, in how many different proceedings do we need to deal with this. And I think especially since there is agency coordination, and CEC Staff consults with PUC Staff, so our suggestion is to eliminate this bullet from the scope of this series of workshops.

In any event, whoever is considering rate design, TURN reiterates our position it has taken in all the proceedings, energy efficiency is already inherent in the residential rate design that has increasing tiers. And energy efficiency is the first in the loading order.

So our existing rate design supports the most important goal. And we should not throw out the existing rate design in favor of demand response. It can be maybe integrated in some way, but we should remember the priorities.

Second comment concerns load management standards. The OIR for this proceeding did

mention that there were initially standards on pool pumps. And we didn't hear anything today about the status of that. But our feeling is that is a very important area for further work of this Commission. And so if standards could be looked at for pool pumps because that is, as Commissioner Rosenfeld pointed out, about the second largest use. So we would encourage this workshop to look at those sorts of things.

ASSOCIATE MEMBER ROSENFELD: Gayatri, let me make a friendly remark. All the three utilities are going to be doing pilots as they introduce their AMI and first PCTs and second will be pool pumps.

I've already been urging them to make pool pumps a part of those pilots and see how it works, and you could urge them, too.

MS. SCHILBERG: Well, that's good. This is the first I heard that they are going to be doing that in their AMI. So, maybe there is some benefit to that anyway, huh?

Customer education. We totally support the goal here of looking at customer education. And would encourage the Commission when you are making efforts to educate customers, that you also

educate with respect to general conservation.

Because somehow at this point even though we do have a rate design where higher consumption costs more money, and therefore it would be logical to reduce consumption, customers are not aware enough of the ways that they can reduce overall consumption; and that the fact that when they get into the higher tiers it's going to be more and more expensive.

So, we would encourage any education efforts to cover both demand response and energy efficiency. And help people get out of those higher tiers.

And the last topic is devices such as PCTs. In the event that they are considered in this proceeding or the Title 24 proceeding, whichever proceeding we would hope that the cost effectiveness test does not duplicate some of the benefits which utilities are already claiming elsewhere, such in AMI.

For example, now Edison is going to be putting some PCTs into its AMI application, and it is claiming the benefits in terms of megawatts reduced towards its AMI. So now if at the CEC the Commission chooses to mandate additional PCTs,

there shouldn't be any double-counting of benefit. So we would hope that whatever way that goes with PCTs, that the cost effectiveness test will not duplicate benefits that have already been considered elsewhere.

That concludes my comments.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Barbara Barkovich on behalf of CLECA.

MS. BARKOVICH: Thank you very much. This is clearly the consumer part of the program. I'm here representing the California Large Energy Consumers Association, and I wanted to just make a couple of points, and I'll try to be brief.

One of them is I have some sympathy with Gayatri's comments about raising rate design --

(Ceiling tiles fall.)

COMMISSIONER CHONG: Oh, my goodness.

MS. BARKOVICH: Well, that's exciting.

MR. SPEAKER: Brought down the roof.

(Laughter.)

MS. BARKOVICH: Does this happen often?

(Parties speaking simultaneously.)

MS. BARKOVICH: Was that a signal I'm not supposed to talk very long?

(Parties speaking simultaneously.)

MS. BARKOVICH: Okay, let's try again.

PRESIDING MEMBER PFANNENSTIEL: I'm sorry, go ahead, Barbara.

ASSOCIATE MEMBER ROSENFELD: You should probably start your sentence again.

MS. BARKOVICH: Okay. There is a concern among the consumer representatives, and probably others, as well, of the number of different forums in which we are addressing matters related to demand response, including rate design.

And I know that I had not anticipated spending so much of my life driving to Sacramento and Folsom, as well as San Francisco, in order to address these issues.

And we have noticed, as Gayatri pointed out, the fact that the Commissions and the ISO are coordinating. I also understand the statute does specify the rate design as one of the items related to load management, because I remember when the statute was passed.

But I would urge you, at least, to try to take into account the limited resources, in particular of customer reps like me who don't get intervenor funding. And in a couple of ways.

One is that you have to address rate design to try to coordinate as much as possible, to try to avoid something that has been a problem for us, which is overlapping workshops, energy efficiency, demand response on the same day.

One day was really good; there were three of them, two in San Francisco and one in Sacramento. And when there's only one of you, it just doesn't work very well.

So, you know, for those of us, for example, who are involved in dynamic pricing and the demand response dockets at the PUC, trying to follow the ISO and what you are doing, we would just appreciate it if there could be some sensitivity to our limited resources, because we obviously have great interest in these subjects.

The next point is Gayatri mentioned cost effectiveness analysis. We know that there's a docket at the PUC and there's a proposed settlement for the Commission on DR cost effectiveness. I would only like to add that a source of enormous frustration for some of us is the fact that when a utility makes a filing, for example, through an advice letter, to propose a new demand response program, the avoided cost

information which goes into the cost effectiveness analysis is confidential.

So it's impossible for those of us -- I'm already in 15 dockets, but I can't be in all of them. Unless I'm actively involved in a case and can make a request, file an NDA and get the confidential information, I see a decision that says that a certain utility program has a benefit/cost ratio of .9 to 1.1 or something like that. And I have no idea what that means, because I have no idea what costs for avoided generation, for example, avoided capacity, were included in that particular calculation.

I don't know how that compares to the incentive payments that are made for other DR programs, et cetera. And there is a concern that as long as we're spending ratepayer money we want to make sure it's as cost effective as possible. And it doesn't seem as though all those things really ought to be confidential.

And maybe they won't be going forward once the Commission adopts a methodology. But I believe the methodology will still allow for calculations. And I would urge you to add some additional transparency to the process of

evaluation.

Number three. I think if you read about the event in Texas and ERCOT last week you will see that they would have had serious problems without emergency programs. We would strongly urge you not to eliminate all emergency demand response programs in the interests of moving towards price response or demand response.

And would note that we believe, and you may think that this is self-serving, and it is, but I still believe it, which is that not all worthwhile demand response can be fit into a set of standardized ISO wholesale product categories.

And we filed extensive comments in the scarcity pricing working group at the ISO about this last week. So, I'll send them all to you so you don't have to listen to me talk about them. Because I know time is of the essence.

Thank you very much for your time.

COMMISSIONER BYRON: Quick question, Ms. Barkovich. The cost/benefit analysis transparency issue that you raised, is that occurring at this Commission? Or are you using the PUC as an example and you want to make sure it doesn't occur here, as well?

MS. BARKOVICH: I was using the PUC as an example, since Commissioner Chong was kind enough to come here. And I would simply hope that when you do cost effectiveness analysis that you look at the avoided capacity and if there are any minimal energy costs. And try to do it in as transparent a way as possible.

One of the difficulties we have, as you know, is that there's just a -- let's take avoided capacity costs, which are a central issue in DR. The range of estimates, or calculations that have been performed, vary by a factor of three.

And that means that depending on what number you use, something can either be very cost effective or very not cost effective.

So, we're just concerned that there be some consistency also in keeping with the rate design issues.

Thank you.

COMMISSIONER BYRON: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thanks, Barbara. Jim Crossman, Financial Energy Management. I do not see him.

COMMISSIONER CHONG: Injured by the falling tile.

PRESIDING MEMBER PFANNENSTIEL: Jane Turnbull, League of Women Voters. We are delighted to see you back, Jane, welcome.

MS. TURNBULL: Thank you very much. I'm very very pleased to be here, as well. And I thank all of you Commissioners for this extremely exciting day. It's a day we've been waiting for.

I'm Jane Turnbull. I'm here on behalf of the League of Women Voters. The League has got a study position that supports demand response including the use of tariff design to reduce peaking power needs.

This is a position that was arrived at on a studied effort on the part of 70 Leagues across the state.

On the other hand, we certainly do agree with the previous speaker that tariff design should be an expedited process, not a convoluted process.

The League acknowledges the importance of public understanding of these issues. And that implies that the public has to understand how the electricity system works, how the natural gas system works. And that is not a simple process by any means, as we have found.

We suggest that you use the effective talents of FlexYourPower because that has reached the public in general in terms of what energy issues are across the state.

We also believe that it's important to tie the peaking power implications with the greenhouse gas implications. And so demand response does have a role in the AB-32 considerations, as well.

The League believes that individuals have a personal responsibility in addressing this because it really is a public good issue. But at the same time, it's really important to insist on some consistency in terminologies.

I think many of us understand critical peak pricing and real-time pricing. But if you're going to go to the general public with two different terms the public is going to get confused. So I think it's very very important that the issues of terminology be addressed early on.

And one final point. I moderate a statewide energy e-list of League members. And when the subject of the PCT came out a few weeks ago I got a deluge of emails from across the state

saying what in the world is going on. You know, the implication that this was not going to be voluntary was frightening to the average public.

Finally the tone of the discussion was moderated and it became a very civil dialogue overall. But I would like to make the point that the League supports a voluntary process. But we also would support a process which is an opt-out process, not an opt-in process, because we do think that this is a very important step forward.

Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Jane.

ASSOCIATE MEMBER ROSENFELD: Jane, I have one comment. I'm really looking at Commissioner Chong, but this decision between -- you said it's confusing that there's -- you have to decide between real-time pricing and critical peak pricing.

I think the PUC proposes that only for large customers who have energy managers. For the general public, for small commercial and residential I think the proposal is only critical peak pricing.

COMMISSIONER CHONG: Yes.

ASSOCIATE MEMBER ROSENFELD: She's nodding yes.

MS. TURNBULL: I think the public would be interested in real-time pricing, as well, though. I think the residential customers would be. But, I don't think it should be ruled out.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Klaus Schiess from KS.

MR. SCHIESS: Schiess. If you say it the other way you're swearing.

(Laughter.)

MR. SCHIESS: Sorry. My name is Klaus Schiess, KS Engineers, San Diego. I'm a consulting engineer. Some people call me the Moses of thermal energy storage because awhile ago, a few years ago I gave a presentation at ASHRAE and I sneaked in the Ten Commandments for thermal energy storage. And, yes, it was fun.

But the first commandment is the one why I did the whole thing. And it says, there shall be a rate schedule that makes thermal energy storage economically feasible. Otherwise there are hardly any reasons to do thermal energy storage. We need a rate schedule. That means we need a fertile ground for thermal energy storage

to have a reason.

And I don't even think we need rebates incentives if there is a rate schedule. And I would actually say now, idealistic, we need a rate schedule for the whole state, perhaps for the whole nation, which guarantees the difference of onpeak and offpeak energy costs or demand costs, doesn't matter how, to insure and guarantee for the next, I don't know, ten years, so that investors and builders and people that want to build central plants can invest and know this is the predictions we can have.

Thermal energy storage is the most neglected demand-shifting optional device we've had. When I came to America 50 years ago it was at the beginning. And I really thought this is American. Within 10, 15 years there won't be a building with a central plant and no thermal energy storage system.

We had incentives. People got educated. Utilities went around, and we had special rate schedules for that. And it started to build up. Unfortunately there was some bad designs, some bad manufacturing. And unfortunately a lot of lawyers after that made a lot of money on that.

And then I think probably because of deregulation the whole thing just kind of inflated. It is really only now -- how did somebody say, the sky opens up and maybe thermal energy storage is having a renaissance, and it's probably starting perhaps with these critical peak rate schedules.

But I have tried personally, it's my passion. I don't sell any equipment. I used to design it. I still try to help customers with what they have, and make it -- you know, the rate schedules change so often that you go to tweak your system to get the best out of it.

So that rate schedule would also help wind energy, gas-fired energy and probably photovoltaic. So if the Commission, the government must put down a fertile ground for these demand-shifting opportunities to grow.

I personally, because I'm passionate about this, I made a presentation which I've tried to present. I have presented it to various members of the Energy Commission. They all said, this is for Art Rosenfeld. I have tried your office over the last one and a half years, a few times, by email, by telephone. I never got past

your -- I never met the lady. She always promised I'll get you back; he's very busy; he's on vacation. I never got through to you.

So, this time I would like to ask you, can I come with a 10-, 15-minute presentation to explain to you what is needed to get thermal storage off the ground? It is relatively easy.

And for instance, now I'm going to say something, maybe will take that home.

ASSOCIATE MEMBER ROSENFELD: Let me make two remarks right now. First of all, of course you can come. I tend to do email and stuff until midnight, and then I quit.

MR. SCHIESS: I don't think it difficult to you. You have a good --

ASSOCIATE MEMBER ROSENFELD: But let me make two remarks. I believe -- I'm, just to the rest of the audience, critical peak pricing, as Commissioner Chong is proposing it and as I certainly favor it, will have time-of-use every summer afternoon. So certainly for large commercial buildings, certainly new ones, it will certainly greatly favor thermal storage.

I would also like to make the point, however, for new homes it's not clear that it

won't do a lot of good without favoring thermal storage, the execution of a -- thermal storage stored at every house. And I believe that critical peak pricing will save a kilowatt per house without thermal storage.

But I think we both agree that for large buildings it makes a great deal of sense.

MR. SCHIESS: But what happened the last 12 years?

ASSOCIATE MEMBER ROSENFELD: We didn't have critical peak pricing.

MR. SCHIESS: Why did thermal energy storage kind of nearly take the air out of it? Because I can't make it pay anymore. I mean I do feasibility study, I cannot go and tell my schools which design new chiller plants, I cannot say it anymore. Because there is no rate structure. The rate structure we used to have a demand charge of up to $25. Now it is reduced to half, and then they sneak in a real, you know, the daytime. Then they took -- they increased the ratchet, which takes the profitability away from thermal storage.

And --

ASSOCIATE MEMBER ROSENFELD: We are both advocating critical peak pricing. So I think when

we raise --

MR. SCHIESS: Great. I think we have now turned the thing that be going up. But it's a pity that we wasted 10, 12 years for that.

Now, another little question I have. The utilities, they want demand response. Why? Well, they like it because it's a short term, for a few days when they're in trouble, they lose that much demand income.

But what if you do it the whole month? Then they lose so much. That's why I don't think there's an incentive, really, from the utilities to go for thermal energy storage.

I've had SDG&E representatives go around to clients and say, you know, scrap your thermal energy storage system. Use it as a demand shift device. That is absurd.

And why do you say five or ten days you have -- you take the demand shift you get for the five to ten days and compare it. Well, if these people do demand response, they say, well, gee, I could actually do this the whole month. Suddenly they get penalized.

So I would suggest the government has to put on a rate schedule, unified preferably

statewide, to get thermal energy storage off the ground.

PRESIDING MEMBER PFANNENSTIEL: Thank you, sir.

MR. SCHIESS: And I see your faces; they're not smiling anymore.

(Laughter.)

PRESIDING MEMBER PFANNENSTIEL: John Sarden.

MS. SPEAKER: Oh, I think he's online. Joe? Hello? Hello. Hi, Denise. Can you put John Sarden on the line?

(Pause.)

MS. SPEAKER: He hung up, okay.

PRESIDING MEMBER PFANNENSTIEL: Ben Metha.

MS. SPEAKER: Is Ben Metha still there?

MR. METHA: Yes. Ben Metha calling you from Energy Connect in Acampo, California. And it's (inaudible). But out of two or three (inaudible) to the audience and the Commissioners, we are very actively doing (inaudible).

I want to (inaudible) two or three more very critical areas that we are facing. Some are found on the list. This year PG&E has stopped

offering any technical -- funding for large, commercial/industrial customers because they used up all the funds. It was supposed to be for two years, they used it up in one year.

So, those customers who have signed up to demand response with this -- utility are not going to (inaudible). Very very poor planning.

The second is the fund from the (inaudible) budget and for whatever reason it was depleted much faster than made available to the customers.

The second point is there also a very similar issue, metering by utilities. Because programs requires that if you are not a 200-kilowatt customer, you must spend a lot of money to add the -- meter. Otherwise you cannot (inaudible). These costs are prohibitive particularly for customers who have (inaudible) each outlet in the small aggregated (inaudible) potential. But they're not going to spend X-thousand dollars for a (inaudible). This is (inaudible).

And the last, also an opportunity that I heard a lot about that and saw it. There is some very interesting work being done by Mary Ann and

her staff. And it is to use the building materials for storing (inaudible). You can (inaudible) building and use that energy storage for the peak time usage. And they have documented some -- that look very effective. And I was against the Commission to make the funding -- that this is a very interesting option, along with demand (inaudible).

So that's three areas to the list that's (inaudible).

PRESIDING MEMBER PFANNENSTIEL: Thank you very much, sir. Richard Howburson.

MR. HOWBURSON: Can you hear me?

PRESIDING MEMBER PFANNENSTIEL: Yes.

MR. HOWBURSON: Okay. I've been really -- at demand reduction, and I've been doing it for about eight years. I think I'm really impressed by what happened. I thank you very much for inviting me to participate today.

What I found out that with education and most of your presentation today was very good about education. And the thing is I think it has to continue. I've been working with San Diego Gas and Electric; I've worked with Edison. I haven't been up with PG&E. LA Power, and so forth,

Anaheim.

The thing is that people don't really understand this. And this is why I think we have to implement an education program. We have to have logistics to put it in. And we have to go forward.

The thing is it isn't that costly to put it in. But, when you get a rebate, return on investment of eight months to a year, and the customer still doesn't do it, I don't know what else to do.

And I've proven it. (inaudible) to go in and take out and record it all. And I send it up to the Energy Commission. I've been working with Valerie Hall; I send things up to her.

What you're doing here today is (inaudible) because it was a lot of things. I'm humbled by all the things that are going on and that we can win this war of energy. Especially with oil going up so fast, I don't know what we're going to do. Especially Edison, I guess, they're there. I went and talked to Mark Martinez. I think he's probably up there. I couldn't afford to come up all the time, but I think this is a very good way of doing it to get other people

involved.

And I think that with Edison I think you have 50 percent of their generation is fossil fuel. And if this keeps going on, this work keeps going on, we're going to have to put our nose to the grindstone and get it done.

There's logistics that have to be done; implementation. And we have plans, we can do it quickly. But we have to put people to work and get it going. And it has to be approved.

So I don't know how to do it. I've been calling up on the San Diego Gas and Electric for about eight years. Edison, I have no takers. I think that we have to work as a team. And when you can save 750,000 kilowatt hours a year, that's a pretty good saving I would think.

PRESIDING MEMBER PFANNENSTIEL: Thank you, sir. John Arsenas.

MR. ARSENALAKE: Jim Arsenalake (phonetic)?

PRESIDING MEMBER PFANNENSTIEL: No, that's not what I have. But, yeah, go ahead.

MR. ARSENALAKE: Of Peaking Power.

PRESIDING MEMBER PFANNENSTIEL: I don't have an organization.

MR. ARSENALAKE: Okay, well, I'll speak then.

PRESIDING MEMBER PFANNENSTIEL: Go ahead.

MR. ARSENALAKE: Just that I'm from Peaking Power. We did the flywheel energy storage project that Mike Gravely talked about. We appreciated all the help with that. We think it was successful and demonstrated the technology of flywheels doing -- regulation.

And we're in the process of commercializing that. And I guess the place we need help at this point is back to the market mechanisms that some of the other energy storage projects talked about.

Initially we pointed out there are mechanisms to get paid, for example the regulation. But there are subtle differences in how it's done with energy storage versus generators, or versus load. And it does require a little bit more work in terms of the market mechanisms to iron out subtle details.

And so the workshop people talked about I think we'd appreciate, if we can move to the next step.

So, I won't repeat everybody else's, but thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Samantha Orney.

MS. ORNEY: Good evening. Thanks. I'll make my comments really brief because I know it's been a long day for everyone. But I just wanted to -- I didn't have any prepared comments, I just wanted to make a couple brief ones here.

We have been -- Honeywell, as a company, is very diverse. We're a manufacturer of thermostats, but we also do a lot of utility services through the programs on demand response around the country and here in California. So we have kind of a wide portfolio of interests in this particular issue.

We do want to just -- I do want to say on behalf of Honeywell, from all of our divisions, that we have really appreciated the opportunity to work with the CEC, work with the utilities, and the CPUC on developing not only the load management programs, but also working on the specification for the PCT.

We realize now this is out of the Title 24 process. As to where that particular issue

settles I'd just like to make a couple points that are important from the manufacturer perspective.

One, we need a settlement on a specification. We really need some certainty on that. That is one of the most important things to a manufacturer obviously, in developing a product line and putting out a product that is just wonderful and delighting the customer, the consumer, but also that meets all the objectives of the regulatory community and also our utility customers, as well.

So we really are hopeful that we get to a point certain on that. And in that we are hopeful of an open standard from a communications protocol. And really from this expansion port idea we've had some concerns, but I think we're really here today with the utilities and going forward, and looking at this and saying, you know, a communications protocol.

We don't want to make a thermostat that's just for California. We want to make a thermostat that's for all 50 states, maybe conceivably some type of worldwide thermostat.

So that's kind of what we're looking at. I think a open flexibility there is an important element.

I did talk about certainty. And then we also want to reiterate, I think, what everyone here is singing in chorus, which is again the customer option on this particular issue. And we're very sensitive, obviously, to customer sensitivities. We design our products with a lot of customer input.

And in the regulatory and political process, which is where I work, obviously the customer is the regulators, but also the consumers of our products. So we like to take the input from all sides, and hopefully be responsive to that.

So, thank you very much. I appreciate the opportunity to comment.

PRESIDING MEMBER PFANNENSTIEL: Thank you for being here.

ASSOCIATE MEMBER ROSENFELD: Samantha, don't go away. I'm obviously very interested in this. My point of view is everybody work together to get around this design. It would have been nice if it would have followed the Title 24 for design. But we're so close.

Have you talked with the utilities? We have two manufacturers here. We have three, four

utilities including SMUD. About just sort of going ahead and taking -- reference design and --

MS. ORNEY: Commissioner Rosenfeld, directly to that point. I personally have not had that conversation. Some of our utility service business has had that type of conversation as far as, you know, taking a design and going forward.

Whether it specifically is what has been developed with the Title 24 reference design and specifications, I think our preference would obviously be let's get a design set. You know, I know that was your preference. Whether it's in the building codes or wherever, but let's get one, let's settle on it so we're not making or being asked to make a different thermostat for every utility and Home Depot and everybody else.

But we will definitely have that conversation. And I know Mark Martinez is back here. He'd probably -- I'd be happy to talk with him; and I know he's talked to some of our folks, as well. And there's been a lot of communications between our utility group and the utilities.

PRESIDING MEMBER PFANNENSTIEL: Thank you.

MS. ORNEY: Be happy to do that. Thank

you, Commissioner.

PRESIDING MEMBER PFANNENSTIEL: I'm not sure I got the name right. Paul Angelopulo from DRA.

MR. ANGELOPULO: Good afternoon, Commissioners. I'm sorry I just put the card in a few minutes ago. I'm an attorney at the California Public Utilities Commission, and I typically represent the Division of Ratepayer Advocates.

I'm here more to ask a question than to give an opinion. I had spoken to Gayatri Schilberg and Barbara Barkovich earlier, see whether they're going to address the rate design issues, the rate structuring.

DRA has a concern; it's more a question of -- I mean, I've looked at the Public Resources Code section and there's a little fudge room there interpreting which Commission is going to be doing the rate structure design.

It is subject to the approval of the PUC. But DRA is interested in knowing do you want the consumer advocates' input? To what extent would you like the consumers to contribute to your consideration of these issues as far as rate

design goes? Or are they going to be left totally to the proceedings within the CPUC?

PRESIDING MEMBER PFANNENSTIEL: I believe the answer is when we reach the point of considering rate design, we'll make that determination. Whether we're going to do some independent work here, or work just through the PUC hasn't been decided.

MR. ANGELOPULO: Okay. Just we didn't want to miss the boat. We just wanted to know if you need the contribution of the ratepayers, we'll help you in terms of determining the scope, to what extent rate design issues are going to be considered.

PRESIDING MEMBER PFANNENSTIEL: Thank you.

MR. ANGELOPULO: We do want to reiterate that we have the same concerns that TURN and CLECA have in that there is tremendous resource issue, and that it would be preferable to all the consumer groups to have those rate design issues, specifically load management. Sort of a bill impact analyses that are very intricate and detailed. It's way more efficient to have it done in one forum rather than a few.

PRESIDING MEMBER PFANNENSTIEL: Understood. Thank you.

MR. ANGELOPULO: Thank you very much.

PRESIDING MEMBER PFANNENSTIEL: Any other? That's the remainder of the blue cards that I have. Any other people here who'd like to make a comment, or anybody on the phone?

Okay. I think we should -- let me just offer some thoughts on next steps. I won't be very inclusive because, in fact, we'll get back together with staff and the Efficiency Committee will discuss, and we'll talk with Commissioner Chong and make sure that we are coordinating with the PUC.

I would intend to have some further workshops, presumably joint workshops, or at least jointly participating workshops where we investigate a couple of the issues that came up today in much greater depth.

Clearly we heard a great deal about the enabling technologies, what those might look like, and how they might be done. I think we heard, or at least I was conscious of a lot of discussion about consumer information and education and need to involve the consumers. And make sure we're

communicating in a way that works for them.

We certainly want to stay abreast of what the utilities are doing in their metering, although I would have to say it sounds like where the PUC is is just a matter of us keeping track of what's already going on there.

I don't know, and, David, you can remind me, whether there was any indication of further written comments expected from the public.

MR. HUNGERFORD: Further written comments will be accepted.

PRESIDING MEMBER PFANNENSTIEL: But there was no date given for any comments?

MR. HUNGERFORD: It's the 19th.

PRESIDING MEMBER PFANNENSTIEL: Oh, okay. You're expecting --

MR. HUNGERFORD: The 19th of March.

PRESIDING MEMBER PFANNENSTIEL: Any last thoughts, Rochelle or Art or Jeff? Rochelle, go ahead.

COMMISSIONER CHONG: Thank you. Well, I wanted to express my thanks at being included today. I thought it was a very interesting day and I learned a lot. Wanted to thank everybody that came.

Personally I thought I might suggest adding onto your list if there's any way we can facilitate some of the standards that need to be set for enabling technologies. I'd like to think about whether we could, not in a regulatory forum, but an informal forum, attempt to facilitate a standard being set without it being a regulatory action.

We've done similar things at the FCC, when I was there, as to some wireless standards. So, I have in mind a model I think could be used.

PRESIDING MEMBER PFANNENSTIEL: Excellent.

COMMISSIONER CHONG: So that's a thought. On consumer education I would like to second that very strongly. It seems to me there is a lot of money being spent on consumer education, but perhaps not in the best way.

I am thinking that if we were to recast in a more focused way some consumer education on themes including energy efficiency, try and explain demand response to consumers, preparing them in advance for time-of-use dynamic pricing that we could do some very valuable work on behalf of the consumers of California.

So I wanted to let the consumer groups know that I heard that very strongly. I believe in that very much. And that we really need to coordinate that earlier than later. And be very creative about the multimedia ways in which we choose to present that.

PRESIDING MEMBER PFANNENSTIEL: Right.

COMMISSIONER CHONG: So, as you can see, we're very busy at the PUC on some of these issues, but I wanted to thank everybody for bringing all of the other issues to me so that we are doing things in a more coordinated manner.

So, thank you, again.

PRESIDING MEMBER PFANNENSTIEL: Art, comments?

ASSOCIATE MEMBER ROSENFELD: I only wanted to say that I'm very pleased with the general reaction today that we're close on a standard which would work for the whole country and maybe even in southern France. And I hope we can follow your example if you've got some hopeful examples.

My own prejudice is I also listened to Barbara Barkovich and several people say that tariff setting is complicated, and more than one

venue is complicated. And I just want to say my personal reaction is I think we have a great working relationship with the PUC already in which we've worried about the hardware and the implementing technology. And the PUC is worried about the tariffs. And from my lazy point of view that's just fine.

That's all my remarks for now.

PRESIDING MEMBER PFANNENSTIEL: Jeff, nothing?

Let me close by thanking everybody for being here, thanking the staff for putting a lot of effort together in getting this.

It was a very useful day. I think it's kicking off what will be a coordinated effort that will result in some changes, some load management standards, and presumably this year.

Thank you all for your effort. We'll be adjourned.

(Whereupon, at 4:50 p.m., the workshop was adjourned.)

--o0o--

CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Efficiency Committee Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 15th day of March, 2008.