EFFICIENCY COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	)	
	)	
2008 Order Instituting Informational	)	Docket No.
Proceeding and Rulemaking on	)	08-DR-01
Load Management Standards	)	
_____	)	

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

TUESDAY, MAY 27, 2008

10:04 A.M.

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

COMMISSIONERS PRESENT

Jackalyne Pfannenstiel, Presiding Member

Arthur Rosenfeld, Associate Member

ADVISORS PRESENT

Timothy Tutt

STAFF PRESENT

David Hungerford

ALSO PRESENT

Tom Roberts
California Public Utilities Commission

Jana Corey
Pacific Gas and Electric Company

Paul DeMartini
Southern California Edison Company

Ted Reguly
San Diego Gas and Electric Company

Craig Kuennen
City of Glendale Water and Power

Cathy L. Bretz
Imperial Irrigation District

George Chen
Los Angeles Department of Water and Power

Erik Krause
Sacramento Municipal Utility District

Rebecca Lee
Division of Ratepayer Advocates

Jeffrey A. Nahigian
JBS Energy, Inc

ALSO PRESENT

Erich W. Gunther
EnerNex Corporation

Richard Halverson (via teleconference)

James Meacham
CTG Energetics, Inc.

I N D E X

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P R O C E E D I N G S

10:04 a.m.

PRESIDING MEMBER PFANNENSTIEL: This is the Energy Commission Efficiency Committee's second workshop on load management standards. Today we're going to focus on the advanced metering infrastructure.

I'm Jackie Pfannenstiel, the Chair of the Energy Commission and Presiding Commissioner on the Efficiency Committee. To my right is Commissioner Rosenfeld, who is the Associate Member on the Efficiency Committee. To my left is Tim Tutt, my Advisor.

I have no opening remarks other than to comment that as we approach the load management standards proceeding the question of smart meters or advanced metering infrastructure clearly is pivotal to anything else that we were able to do, and everything that we want to do.

So, an interesting day. I know we've talked about this with many of you in this room several times. We want to build a record here and see what else we need to do in this area.

Commissioner Rosenfeld, opening comments?

ASSOCIATE MEMBER ROSENFELD: No. I've looked through some of the PowerPoints and it looks like it's going to be a very interesting morning, so I'm ready to go.

PRESIDING MEMBER PFANNENSTIEL: David.

MR. HUNGERFORD: I'm David Hungerford; I'm the Demand Response Manager here at the California Energy Commission.

ASSOCIATE MEMBER ROSENFELD: David, do you have your mike on?

(Laughter.)

MR. HUNGERFORD: Did you say that just for fun, or was I really not speaking into the mike once again?

ASSOCIATE MEMBER ROSENFELD: Thank you, David.

MR. HUNGERFORD: All right, it's become a running joke.

My compatriot, Gabriel Taylor, who most of you spoke with over the -- have spoken with over the past two weeks, is currently sunning himself on a beach somewhere in Mexico, and will be back in a couple of weeks. And I also want to acknowledge Al Garcia who has been working with us on this proceeding.

A couple of logistical issues. Your exits are behind you where you came in, in this main door; and also the other side of the window there are exits if there's an emergency, a fire alarm or anything. Please move to those exits and proceed over to the park across the street to gather.

The door on this side behind you is alarmed. Obviously in the case of an emergency you can go out that door. Otherwise you have to go out the door you came in from.

I would also ask that you silence your cellphones during the meeting. Just a reminder, we all know this.

One other issue for future workshops that we need to pay attention to. Starting Friday night Caltrans is going to be tearing up Interstate 5 here in the downtown section. And it's going to be ongoing for the rest of this workshop schedule. And there will be no way to get through there.

The traffic is likely to be bad and congested coming from the airport and coming from San Francisco in on Interstate 80. My advice is to, if you're coming from San Francisco is to take

the train. And then either cab or take the half-mile walk from the train station over here to the Energy Commission. The weather should be nice.

There is a website --

ASSOCIATE MEMBER ROSENFELD: But, David, David, --

MR. HUNGERFORD: -- that you can go to for information --

ASSOCIATE MEMBER ROSENFELD: -- as a train rider, I have to warn you that they're also tearing up the tracks between Fairfield and somewhere, Benecia. So the train during the day is going to have buses going across the Benecia Bridge. So beware or look up www.capitolcorridor.com. So we're in for a bad month.

MR. HUNGERFORD: I revise my advice to say maybe you should come in the night before.

(Laughter.)

MR. HUNGERFORD: And there's a website that can help you with the logistics for getting around, for the mapping and getting around the alternate routes. And that is www.fixI5.com.

I also want to make everyone feel comfortable about coming up and speaking at the

microphone today. All of the ceiling tiles in this room have been re-glued --

(Laughter.)

MR. HUNGERFORD: -- since our last meeting. And Joe Bubico, who is the manager of this room, has made sure that nothing's going to fall on anyone this time.

And with that, I think I shall take us to meeting mode, or to -- my eyes are failing, folks. And you all have some agendas that were -- they were on the table this morning. This is the order that we're going to go in today. And we haven't got times listed here. We figure we can get through this without -- get through everything on the agenda without having specific times.

Let's go to the first presentation. Okay. Some of you have seen some of these slides before. Just as a general background, this series of workshops is in preparation for the development of load management standards. The Energy Commission is exploring different areas where load management standards might be useful in advancing energy efficiency and demand response in California.

Our goals are to assess rates, tariffs,

equipment and other measures that would be most effective in achieving demand response; adopt regulations and other appropriate actions to achieve a responsive electricity market.

And the purpose of the load management standards proceeding is to obtain public -- sorry about that -- obtain information of management standards, explore the potential peak load reduction and load shifting strategies, and explore the coordination of regulatory authority on demand response efforts among the investor-owned and publicly owned utilities.

Our workshop schedule, to remind you. We've already had two workshops, one on the 3rd of March and one on April 29th. And this is the third in a series on advanced metering. We have upcoming workshops on June 10th on rate design incentives and market integration.

On June 19th workshops on enabling technologies and communications. And on July 10th a workshop on customer education needs.

The notices for these subsequent workshops will be posted on the website under the load management proceeding.

Today's workshop, the objectives are to

discuss the status of current AMI efforts among California utilities, both publicly owned and investor-owned. Understand the technical capabilities of design details of the systems that have already been approved. Explore the relationship between AMI functionality and the capability of supporting different policy goals in California. And to obtain public input on the potential use of the Energy Commission's load management authority.

With that, I would ask our first speaker, Tom Roberts, from the PUC Energy Division, to join me and he has a presentation on an overview for what the investor-owned utilities have been doing under the direction of the PUC.

(Pause.)

MR. ROBERTS: Good morning, Commissioners. My name's Tom Roberts and I'm an analyst with the PUC's Energy Division.

This presentation is going to attempt to explain what is AMI to colleagues who haven't been working directly on this proceeding. I welcome your questions throughout this presentation.

Advanced metering infrastructure, or AMI, is a technology which enables dynamic

pricing. I'm going to discuss an overview, which is going to include the basic components of AMI systems, the benefits they promise to ratepayers and utilities, and the current status of the three projects with our largest IOUs in California.

The main components of an AMI system are new or modified meters, new communication networks and a new data management system.

The most visible component of these systems are the meters, themselves, which are required to measure and store interval data at hourly or finer increments.

As shown in this slide this can be achieved either with a new meter or with an existing meter with an add-on module.

The next component in the system is the communication network between the meters and the neighborhood level data collection units or DCUs, and then between the DCU and the data management system back at the utility's data processing center.

So, when we look at the new hardware it's pretty much the meters, the communication network and the data management system. This is all new. But you really can't have an AMI system

if that hardware and software doesn't connect and interface seamlessly with the existing IT systems at the utility which provides functions such as billing, outage management and website hosting.

And it's that final function which is crucial to what we look to AMI to provide because for the time being that's going to provide the feedback to the customer with their energy consumption and possible pricing data.

PRESIDING MEMBER PFANNENSTIEL: Tom.

MR. ROBERTS: Yes.

PRESIDING MEMBER PFANNENSTIEL: Just definitionally, are you referring to AMI as necessarily providing information back to the customer? Or can you have an AMI system where it's one-way communication, even though obviously we're talking mostly about two-way communications?

MR. ROBERTS: I would say that the PUC envisions AMI as being a two-way system.

PRESIDING MEMBER PFANNENSTIEL: Thank you.

MR. ROBERTS: Minimum performance requirements for AMI were defined by the PUC in 2004, and can be classified into two major groups as shown here.

The first block shows features which enable price-responsive demand response, which really was the PUC's main motivation for promoting AMI. However, the second block shows operational savings and service improvements which could have provided even greater motivation for the utilities to proceed with AMI projects.

Every AMI application which has been submitted to date has met all of our minimum requirements. But for some of the utilities' business cases, the benefits which were provided by these six minimum-function requirements didn't provide enough benefit to overcome the cost, since from the PUC's standpoint AMI must be cost effective.

PG&E was the exception to this. This bar graph compares the potential benefits from their adopted AMI application with that project's cost. And from this you can see that operational benefits and remote meter reading were really the key to approval of AMI's basic AMI application, since they covered 90 percent of the system costs.

PG&E only had to show minimal benefits from demand response programs to demonstrate that the overall sum of the benefits exceeded the total

costs.

Edison and SDG&E, on the other hand, have more efficient meter-reading systems now, and their business cases showed operational benefits only covering about 60 percent of their system costs.

So, looking at the right-hand column over here, the benefits from these two blocks for Edison and SDG&E were much smaller. So, by necessity, they had to provide a system that provided greater demand response.

And they did this by providing additional features such as solid-state meters, which can be updated remotely; by downloading new software; and by adding integral remote connect/ disconnect switches. Both of these increased the operational benefits of their AMI systems.

However, a third additional feature was really the key to the final bullet on this slide, which was promotion of energy conservation, or enabling greater energy conservation.

PG&E's adopted system will offer hourly usage feedback to customers that have internet access on a next-day basis as shown in path one above. This feedback can help identify when and

how customers can conserve energy. However, path two, below, illustrates a more direct and immediate feedback loop which is provided via a home area network or HAN.

ASSOCIATE MEMBER ROSENFELD: Tom.

MR. ROBERTS: Yes.

ASSOCIATE MEMBER ROSENFELD: Go back to that slide. Thank you. I want to ask a question, not of you, but looking at the people who are going to follow in your footsteps in a minute.

I would, myself, be happy if each of the people who are going to present would expand a little bit on this. That is, everybody agrees that there will be the next-day signal coming back over the internet.

I can guess that most commercial and some residential customers will want faster feedback, maybe one-hour feedback or whatever. And would be willing to pay a small fee, but only a reasonable fee to get that. So, I'd like some of the speakers to dwell on that point.

And then on path two, my particular prejudice is that commercial customers will want a lot of path two. And there's the question of what sort of data comes across path two. Is it one-

minute data? Is it 15-minute data or whatever? I don't think that's a job for the regulatory agencies to require, but at least to encourage, that there be some sort of agreed-on California-wide protocol.

The only other question that I'd like the presenters to talk about is back to your slide three, which had the various collection of meters on it, I'd be interested in just personally knowing, in addition to the electric meters which you've been dwelling on, I'm not up to date on, but it seems to be efficient to coupling the gas meter; and, in fact, it seems to me to be efficient to coupling the water meter, I'm sort of surprised there isn't a more widespread discussion of that. I'd like to pick up some information on that, too, as we go through the talk.

So, I'm just praising you for raising the right questions. Thank you very much.

MR. ROBERTS: Thank you.

PRESIDING MEMBER PFANNENSTIEL: And on the subjects, any idea of what percentage of residential customers do not have internet access?

MR. ROBERTS: I don't have that number, but I'd be glad to look into it and get back to

you.

PRESIDING MEMBER PFANNENSTIEL: We can talk to the utilities individually about it. Thanks.

MR. ROBERTS: Okay. And I would just like to point out that in this slide this middle meter is a gas meter, and it shows that it's got the add-on module using the existing gas meter hardware.

And to address just partially one of your questions, Commissioner Rosenfeld, they had a symposium last week in Santa Clara called "Connectivity Week" and there were a number of vendors and presenters talking about what could be provided via that HAN gateway or HAN system.

And my understanding was that one of the nice things about the protocol which we seem to be moving towards is that not only can the meter be set up to send a signal out over the home network, which is kind of shown here, at a given interval, but the thermostat or a HAN-enabled computer terminal could also ping the meter and ask for data.

So we may choose to establish a protocol for how often data is transmitted over the HAN,

but I think one of the benefits will be if there's a two-way communication path where if a consumer wants information more often, and they want to average that data on their terminal, they could do that, themselves.

ASSOCIATE MEMBER ROSENFELD: So this is sort of the responsive meter?

MR. ROBERTS: Yes.

ASSOCIATE MEMBER ROSENFELD: But, again, at the risk of repetition, you guys have to come up with some sort of a recommendation for what that -- is that data one-minute data or five-minute data or shorter intervals? Although shorter intervals are pretty hard to read and pretty noisy.

MR. ROBERTS: Okay.

ASSOCIATE MEMBER ROSENFELD: Thank you.

MR. ROBERTS: Yes.

ASSOCIATE MEMBER ROSENFELD: And I notice there on this nice plot here that you are collecting, you do show a dash-line to the water meter.

MR. ROBERTS: Correct. And the gas meter, as well.

ASSOCIATE MEMBER ROSENFELD: Sure.

MR. ROBERTS: So, this graph was provided by Edison. And this is just going a little bit deeper into the concept of a home area network, which probably everybody in this room fully understands, but I'm just going to talk to the slide anyway.

SDG&E's adopted system, as well as the pending applications for Edison and PG&E, include a wireless system which allows appliances, utility meters and the user's computer terminal to talk to each other using the HAN.

This vision requires that all the devices speak the same language. And fortunately, it does appear that within California, and possibly nationwide, consensus is building towards a common protocol which is known as ZigBee.

And as somebody new to AMI the best way I found to think about it is that it's Bluetooth on steroids. It's got the same level of smart connectivity, just over a wider distance.

HAN will enable customers to obtain near real-time consumption data from any ZigBee-enabled device within the home, including the AMI meter. And as I mentioned, devices such as an inhome display device that you can put on your coffee

table or refrigerator or on the wall, those products, real products that are available for sale, were demonstrated last week in Santa Clara. So, this isn't just PowerPoint products. These are real products that are on the market now.

The HAN system will provide even greater DSM benefits if real-time pricing is adopted. And I think we're all familiar with the example that the meter could talk directly with the programmable controllable thermostat, and that the customer could preprogram their thermal and economic preferences into that, and have it respond automatically to hourly pricing if the meter was able to broadcast that.

Such a network really maximizes the impact of demand response programs by tailoring it to the preferences of the customer, and by reducing repetitive action required of the customer. And I think in this regard it makes DR systems, this particular type of system, much more analogous to an energy efficiency measure where a customer has to make an initial decision to be efficient when they, at one point, at the beginning of the process. But then they really need to take no further action to enjoy energy and

bill savings.

And certainly as shown by this graphic, HAN-enabled pool pumps, water heaters, kitchen appliances could all be similarly programmed and responsive to either signals over the HAN from the utility, or they could direct signals from their own computer if they wanted to come up with a more customized program for their own home.

As you're probably well aware, each major utility has a current AMI project in some form. What I'm going to talk about are systems primarily for small customers with demand less than 200 kilowatts, since the utilities already have programs for their larger customers.

Each IOU is treating the existing large interval meter systems separately, and I don't know all the details, so hopefully that's something we can find more out about today.

PG&E was the first to file an application, and they're still the only utility with installed meters and support equipment. Based on the operational benefits I discussed previously, PG&E initially chose a low-cost, low-risk system which primarily uses retrofitted meters rather than new meters.

However, their application required that they monitor advances in AMI technology, and they have switched from the DCS electric meters which communicated over the powerline to solid-state meters which use the same RF system as their gas meters.

It's not clear to us at this point exactly how this change relates to their upgrade application, which was filed in December, because that application is still pending before us, but we are starting to work with PG&E to understand how this will affect their revised deployment schedule.

SDG&E's application specified the functions of their AMI system, which provided the basis of an RFP process used to select their vendors. If they can finalize their contracts in the next few weeks, and the Commission approves them, they can begin their mass deployment in the second quarter of 2009.

Edison was the last to file an application, but they have already selected Itron as their main vendor. And we have a PD on their application which is due out this summer. And if it's approved, I think it's possible that Edison

may fully deploy its system before PG&E's final system is deployed in whatever form that may be.

I included the next two slides primarily as reference, but there were two important points that I wanted to note. First is that if Edison's application is approved, ratepayers will invest over $4 billion to install over 16 million meters by 2012.

These numbers will increase if PG&E's upgrade or SoCalGas' potential application are approved. I also wanted to note that the number here for the approved budget for SDG&E is actually $572 million.

This next slide compares features of each AMI application and illustrates that if PG&E's new application is approved the state's major utilities will have comparable AMI systems which provide greater function and DR benefits than the PUC's minimum standards.

But this condition where everybody has the same color, which signifies basically having the same functionality, will only happen if PG&E can demonstrate that the integral remote connect/ disconnect solid-state meters with the ability to have remote software upgrades and the ability to

have home area networks provides benefits which exceed the incremental cost of their upgrade.

Finally, we wanted to place AMI within the context of last month's workshop on smart grids. The PUC team's unofficial position at this point is that AMI systems will likely be a building block to the smart grid. Deployment of AMI systems which promise to enable price-responsive DR and energy conservation has begun. But smart grids are not even defined yet.

And when you look at everything that has to be encompassed with smart grid, I think even if we do define it in the near term for various state and federal legislation, which are requesting that definition, that that definition will likely evolve over time due to technological advances in energy storage, distributed generation and the like.

Given that evolutionary process we really feel it's premature to comment on AMI's specific role with respect to smart grids at this time. But the PUC will be considering this in response to Title 13 of the Energy Information and Security Act of 2007.

That's my last slide, so thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you very much. Questions?

ASSOCIATE MEMBER ROSENFELD: I just want to say I think that was a very nice summary presentation, thank you.

PRESIDING MEMBER PFANNENSTIEL: Yeah, an excellent summary, thanks. Tim, you had a question?

MR. TUTT: Thank you for coming and for your summary. The notice for this indicated some possible standards concepts. Is there something that you would suggest that we could do with our load management authority to help things along at the PUC, if necessary? Or otherwise that you would suggest that we might do?

MR. ROBERTS: With regard specifically to AMI, or smart grid --

MR. TUTT: To AMI and load management standards.

MR. ROBERTS: Can I get back to you on that?

MR. TUTT: Absolutely.

MR. ROBERTS: I don't -- I can't think of anything at this time.

PRESIDING MEMBER PFANNENSTIEL: On the

cost effectiveness question, you found that all three, or you need to find that each utility has demonstrated the cost effectiveness of AMI before allowing deployment. And you found that for PG&E's original proposal and you're working on that.

If that -- that becomes a really critical question for widescale, and that means for moving this beyond the investor-owned utilities, did the analysis -- was the analysis quite compelling in each case to find cost effectiveness? Or was it relatively marginal depending on some major assumptions?

MR. ROBERTS: I'll preface my response by saying that I started on AMI last month.

(Laughter.)

MR. ROBERTS: And I haven't actually -- I mean I have read through the applications and the business cases, but I wasn't participating in any of the hearings where that was debated.

I did sit in on Edison's hearings briefly and it seemed to me that they were arguing over some rather small details to establish a cost/benefit ratio just slightly greater than 1.

So I would say, from that limited

picture that I saw, and some of the discussions that I've heard at the Commission, that it's a pretty close comparison, but certainly there's many people in the room that can speak --

PRESIDING MEMBER PFANNENSTIEL: We'll ask them.

MR. ROBERTS: -- to that.

PRESIDING MEMBER PFANNENSTIEL: Thank you very much.

MR. ROBERTS: Thank you.

ASSOCIATE MEMBER ROSENFELD: I will make the point regarding Commissioner Pfannenstiel's last question, that, of course, the big IOUs are going first, bringing down costs for meters and communications pretty rapidly. And so one would hope it will be easier for the munis to come along a year later and show cost effectiveness.

I don't know whether -- I see Erich Gunther is sitting there. Do you want to make any -- and so does Ron Huffman. Does either of you want to make a comment on that issue?

MR. GUNTHER: Not at this time.

ASSOCIATE MEMBER ROSENFELD: All right. Later, he says.

PRESIDING MEMBER PFANNENSTIEL: Thank

you, Tom.

MR. ROBERTS: Thank you.

MR. HUNGERFORD: All right, the next section, the three investor-owned utilities, we've got this listed as a panel discussion. The order I have listed here is that Jana Corey will go first. And what I think I'd like to do is have the three utilities work independently, and then they can all three come to the table at the end for more detailed questions before we break for lunch.

And, so, Jana.

I hope this is the right presentation.

MS. COREY: I'll make it up if it isn't. That's why I always love this particular audience because most people in this room know at least as much as I do, if not more, about this topic. So, raise your hand if I've missed something, or I've not said it properly.

Can you hear me all right?

PRESIDING MEMBER PFANNENSTIEL: I think you need to speak into the mike, because there are people either calling in or on their way.

MR. HUNGERFORD: If you prefer to wander around, we have this.

MS. COREY: No, that's fine, I can stand right here. Okay. All right, thank you.

Okay, so PG&E, first of all I'd like to thank Tom for giving such a wonderful overview. In fact, you're going to see at least one of the slides that he used in my presentation this morning.

PG&E did indeed began deployment in 2006, and we have 10 million meter upgrades. That's about half and half gas and electric meter changeouts. Our business case is predicated on the ability to offset meter-reading costs for both our gas and our electric business. And I think it would be harder for an all-electric utility to really get that full benefit, unless you were a dual-commodity utility like we are.

We obviously are collecting information from our meters and bringing it back to PG&E. We have a very significant infrastructure effort going on on the IT side to be able to manage the volumes of data that we're collecting.

We are collecting hourly interval data for our electric customers and 15-minute -- I'm sorry, for our residential customers, and 15-minute interval data for our commercial customers.

Gas we're currently reading on a daily basis. And part of that, I understand that this is a little bit of an education session, so I'll digress from the main theme to make some observations that I have about how to make a business case pull together.

On the gas side we had a lot of discussions about what benefit you could get from more frequent interval data for a gas business. And that was a very interesting debate, and there's a lot of potential there. But we didn't include any particular benefits associated with the ongoing gas business except for the meter-reading benefits and the other common allocated benefits that would be allocated to the electric and the gas business.

Obviously the objective of our -- obviously the benefit that we were directing our efforts to was to be able to deliver demand response benefits, because the genesis of this whole look at AMI was really from the California energy crisis. So we really focused our efforts both on the deployment side and on the business case side to deliver demand response benefits.

Obviously the benefits to customers are

very crisp. The customer obviously, those customers have to put signs out, or that have to accommodate someone coming into their yard, they'll obviously not have to do that any longer. We believe that there's a segment of our bills that are either delayed for one reason or another that are related to a human going out and reading a meter and making a mistake potentially. So, some of those types of bill errors or delays in billing will be benefitting our customers, because the AMI system has proven to be extremely robust and reliable.

In fact, we did a little trial where we had our meter readers manually reading and our AMI system reading. We did a side-by-side comparison and it was very favorable to the system, interestingly and beneficially to us.

Obviously, the other big huge benefit that this system's going to provide, especially with home area networking, is the ability for a consumer to understand their energy use. And that has a lot of both conservation benefits and demand response program-related benefits. So we're all going to take advantage of those types of programs.

PRESIDING MEMBER PFANNENSTIEL: Jana, what percent of your customers do not have internet access? Of your residential customers?

MS. COREY: I actually don't know the answer to that, but I can find out.

PRESIDING MEMBER PFANNENSTIEL: Yes, could somebody let me know that, I think --

MS. COREY: Yes.

PRESIDING MEMBER PFANNENSTIEL: -- that's going to be important.

MS. COREY: We happen to be very internet heavy in our service territory in northern California, but I can find --

PRESIDING MEMBER PFANNENSTIEL: I believe that's the case, and it certainly is the case throughout California. But there's still -- it's going to be a transition period for some customers, and I'm trying to get just a ballpark of what that is.

MS. COREY: Sure. All right, I have my note-taker in the audience writing that down, I believe.

So, one of the things that we did, this is also an aside, is that for those customers that don't have access to the internet, who can't get

online and see their energy usage, we will accommodate their call to our call center for a paper bill. So they will get the same information; it will be delayed because they'll be getting it via the mail.

We hope that not too many customers will be in that position to have to take a paper bill. Obviously that's much more expensive delivery method than internet service. But, --

PRESIDING MEMBER PFANNENSTIEL: But when you did your cost effectiveness analysis you must have had to consider that.

MS. COREY: When we did the cost effectiveness of the -- we put the costs in for the online system to put customers' information on our website, so that's one cost element that's irrespective of how many people access it.

In terms of our demand response benefits those were programmatically tied to programs.

PRESIDING MEMBER PFANNENSTIEL: I understand. No, I'm saying there will be some percentage of customers who will want a paper bill, who need a paper bill because they have no other way of getting that information. And you must have calculated what that would cost and how

many customers would be in that situation.

MS. COREY: We put call center costs in our business case. I don't know that we explicitly called out the number of customers that would want a paper -- we obviously provide them a paper bill every month, and that will be similar to what they get today with more information.

PRESIDING MEMBER PFANNENSTIEL: Oh, it will be? So you're planning to redo your billing system to provide paper bills of all of the information that's available through the AMI on a paper bill for all customers or just those who want it?

MS. COREY: No, no. The granular interval data will be available via the website. If a customer called, we will create a paper bill. But it mimics what's on the website. We don't anticipate sending monthly bills to every customer that has all the interval data that we've collected that month for them.

PRESIDING MEMBER PFANNENSTIEL: So anybody who does have internet access, who does not request a paper bill, no longer gets a PG&E bill, that's correct?

MS. COREY: Oh, they'll get a monthly

PG&E bill.

PRESIDING MEMBER PFANNENSTIEL: And the monthly PG&E bill will look just like the current PG&E bill?

MS. COREY: I'm not really sure exactly what the new bill will look like. At this point we're anticipating a very similar bill to what we have today.

PRESIDING MEMBER PFANNENSTIEL: But I think that that becomes an important question.

MS. COREY: Yeah.

PRESIDING MEMBER PFANNENSTIEL: Certainly for the demand response feature that we're looking for. There's a question of what information the customer is going to get. Some of it will be real time, some of it will be next day, some of it will be, you know, other ways --

MS. COREY: Monthly.

PRESIDING MEMBER PFANNENSTIEL: -- looking at it. But some of it will be monthly. And I think that's part of what we need to be thinking about.

MS. COREY: Yeah, we have a big bill redesign effort going on, and I'm not really sure I can answer the question --

PRESIDING MEMBER PFANNENSTIEL: You've had a bill redesign effort going on since my days there.

(Laughter.)

PRESIDING MEMBER PFANNENSTIEL: It's been going on for a long time.

MS. COREY: Okay, well, I'm not in charge of that, so -- I will follow up on that, Jackie.

PRESIDING MEMBER PFANNENSTIEL: Thanks.

MS. COREY: Okay. Clearly the benefits -- there's an ancillary benefit, and when you start looking at AMI systems, what becomes -- the meter-reading part of it is very easy to understand and very clear how much the savings are associated with that.

What was really interesting to us when we began to look at AMI was the fact that there's these ancillary benefits like outage detection. And some of the outage capability is almost more exciting than the meter-reading capability.

So, what's important as you look at these systems is to understand what the nature of the outage capability you might get out of your AMI system.

We are eager to implement this, and see how really good the information is that we get. And there's detection and there's restoration benefits. And you need to understand the elements of your system that you're purchasing and what that opportunity is for you.

Obviously, anything that provides a benefit to a customer often translates into a PG&E benefit because it limits our requirement to go back and do extra work. Obviously our power purchase costs are going to be going down because we'll be promoting demand response programs and we'll be benefitting from energy conservation. Obviously, the state benefits in similar ways.

So this is the slide that Tom showed. The one thing I will be sure -- I wanted to be sure and point out to those of you who are looking at business cases, you can read the California business cases because they're public domain documents on the CPUC website.

But one of the things that you may not notice, or you may notice missing is the category of theft. And specifically, theft is not a category of cost that go into -- or benefits that go into our business case. But there are a lot of

jurisdictions around the country for whom that's a very significant portion of their business case.

So if you look at business cases from the east, or whatever, you'll see that as an element in the business case. We recognize that's a benefit to us. We were not able to recognize it in our business case because of our regulatory structure. So I always point that out when I'm talking to audiences that are not California IOUs.

Jackie, your question about cost effectiveness, I just wanted to address that for a moment. One of the things that we were struggling with at the very beginning of putting our business case together, first of all overall on the economic scale, if you think about it, labor costs continue to escalate and technology costs continue to go down.

So I firmly believe that we are in this wonderful sweet spot where it is becoming economic to trade out a manual workforce for technology. And we've, you know, evidenced that here in California by making really good business cases.

And I would suggest that the kinds of business cases that we are showing today, that other utility entities in the state can probably

make those fly, as well. We have seen significant drop in technology costs, even from two years ago when we began our deployment, to today. And that's why we're currently at the CPUC requesting some funding for additional functionality, because not only have costs come down, functionality has increased. Just exactly the way you would anticipate it to do.

The other thing I would mention is that we spent a lot of energy educating our departments on what kind of benefits they might see. And we had people come from all over the United States to talk to our teams, the outage people, the capacity planning folks, the operation of the call center people.

We had a huge education effort going on to make sure people understood in our company you really can achieve these benefits. So we feel confident that the benefits we put up are really really firm, and we can deliver on them.

But there's a lot of speculation, a lot of daydreaming about what else could we do with this data and with this information. And I would suggest that if you sat down and creatively thought through a business case, there's more

here. And we're just beginning to mine that opportunity. So, I would be surprised if it was very hard to make this case.

PRESIDING MEMBER PFANNENSTIEL: I absolutely agree with you. I understand that there's a lot more that's going to be, I think, in the way of savings once the meters are fully deployed.

My question really is in making the case, though, there are some assumptions. And whether they're assumptions on the technology costs reductions or the savings in operations, time or whatever, sort of looking at where are the biggest challenges to capture those costs. Where's the lack of -- where might something be a major savings for PG&E, but maybe not transferrable to other companies.

You've already said, for example, the savings on having both gas and electricity meter reading eliminated, it was a major component for PG&E, which may not be true elsewhere.

I'm kind of looking at your perspective on where else there might be specific savings that you found or uncertainties in your numbers.

MS. COREY: Okay, that's a good

question. Let me tell you where I think the hardest parts of the business case to estimate were.

Obviously the meter reading was fairly straightforward. We have a budget every year for meter reading and we just wanted to turn it to zero at the end of the deployment. So that was a pretty easy chunk of money. And that's a pretty significant portion of the operating benefits.

The things that were complicated were the call center costs. Because we expect there to be a significant increase in call center activity as the meters go in, as programs are being rolled out, as home area networking becomes prevalent. People are going to wonder how does that work for me, how do I get involved, how do I participate. If I have a problem, what do I do.

So we have to put in some additional costs on that call center side, and then estimate what we thought the reductions were. So that's one of those things that's very -- you can have very good data about what types of calls you get, and the ones that say meter reader in front of them, those are pretty straightforward. The meter reader's gone, so there won't be any of those.

But the other categories are very complicated to identify. And I would sort of -- maybe my colleagues can also comment on that.

We have things like the truck dispatches, which is a fairly significant benefit. That's pretty easy to estimate because we know how many guys we send out to turn people on and turn people off. So that's a fairly good number, and it's a big element of the business case.

The billing elements were very complicated to also figure out, because we expected that the things that meter readers made mistakes were going to go away, but we didn't know exactly how much exception work we would get from our new system.

And people in the industry will tell you exceptions are where it's going to really bite you hard. So we made some estimates about what we thought the exception handling would be in the billing side.

And those are things that, you know, they kept me awake for a long time. And it's just long enough now, I stay awake over other things. But, that's one of those things that has yet to play out.

PRESIDING MEMBER PFANNENSTIEL: Are you having to put in a whole new system to accommodate a changed billing process?

MS. COREY: We did put an upgrade to our customer care and billing system because of the volumes of data that were coming in, because they were going to be coming in on the hourly basis. And that was -- it was just not equipped to handle that kind of volume. We re-platformed the system onto a platform that could handle that kind of traffic.

We also had to build what we call a meter data warehouse, which is essentially all of the data that's coming in from the field is going to be poured into this giant warehouse.

And what I think is really exciting and untapped entirely is how can you take advantage of all that information there. We have, you know, we'll be providing it to our customers. There may be an opportunity for energy conservation programs. There's operational benefits, if you have an area that's experiencing outages and you're trying to diagnose it, there may be a way to use that information to do that. There's a lot of opportunity in that data that we haven't yet

really fully mined.

So the other thing on the costs, I will say, that were hard to scope was exactly how difficult it would be to -- and this is the new area, home area networking -- being able to take data from a meter and bring it back to PG&E and take some action on it on behalf of the customer.

And that's still -- we've been trying to put that in our business cases, and it's still a moving target. That whole industry is changing every day.

And this is another area I want to address, Commissioner Rosenfeld's comment about the standards. I think that was your comment about standards.

There is a whole group, open AMI, which I know you're aware of, that is actively involved with vendors and the metering community to try -- or the utility community, to try and come up with good standards that everybody can follow. And meanwhile, we're all picking our technology, picking our language protocols, figuring out what services we're going to provide, figuring the costs out underneath all of that. And that's a huge moving target in my opinion.

So, I think those are the big ones.

PRESIDING MEMBER PFANNENSTIEL: Thank you.

ASSOCIATE MEMBER ROSENFELD: Jana, I want to make one comment. I know you're trying to give a talk, but --

MS. COREY: Please.

ASSOCIATE MEMBER ROSENFELD: -- among benefits, I maybe in my mind wonder, but I just want to make the other qualitative point. And that is we don't know, on straight efficiency, how much this is going to save, but we obviously all believe that if people have displays and get interested in what they're doing, they will do things which save energy all the time.

And particularly if you have the gas meter and the water heater connected in, people will look at their real-time displays and decide that they really shouldn't be irrigating the lawn when it's raining. Or will be able to correlate gas expenses with electric expenses and so on. So everybody seems to agree we're going to save something like 10 percent on energy.

Now, you're talking about costs over five years of a couple billion dollars. And

during five years PG&E's going to collect $25- or $50 billion in revenue. So, a small gain in energy efficiency is going to offset all of this, of course. And I realize you can't put that into the benefit/cost calculation, but it seems big in everybody's mind, I guess.

MS. COREY: We did include -- I'm a little hampered here because I have a -- this business case that I'm showing you now is our original business case. But we have since added in energy conservation in that demand response bar, so it's significantly higher. And we did make an effort to quantify the energy conservation component or benefit associated with putting the system in.

So my cost bar goes up a little for home area networking and disconnect switches and solid state meters. My benefits bar goes up for the benefits associated with that, and the energy conservation.

So we're like everybody else who's trying to identify the value of that energy conservation. We did use publicly available research to estimate, and we tried to be as conservative as necessary to come up with a

positive business case.

ASSOCIATE MEMBER ROSENFELD: And that's all public information?

MS. COREY: Yes, it is. It's referenced in our business case, too.

ASSOCIATE MEMBER ROSENFELD: So, in the record of this particular proceeding, is it possible you could submit a slightly more modern version of what's on the screen now?

MS. COREY: Absolutely.

ASSOCIATE MEMBER ROSENFELD: It will be to your advantage.

MS. COREY: Okay.

(Laughter.)

MS. COREY: All right. Then for sure I can. Okay. Dan, I hope you're taking notes out there. Okay, I think I'm running out of time.

So this is really a numerical articulation of what we just talked about. And specifically, as I pointed out, the -- I think I already gave you a sense of which ones were, I think had the most uncertainty around them. So I think I'll go on.

This is a architectural diagram of PG&E's current system that we have in place. And

the top row shows the electric system, which on the left it goes from electric meter via a substation, public wireless network to a head-end controller.

And I will tell you, these piece parts, whether they're labeled, you know, substation or pole top data collector unit, whether they're labeled head-end system controller, they all have the same, all of the AMI systems have virtually the same three parts. They have an end point, they have a network element, and then they have a head-end system controller. They're all the same. You're going to see it from all the utilities, they look very similar.

So, what PG&E, as Tom so aptly pointed out, we selected a DCSI powerline carrier network. And what we've seen in the last two years while we've been monitoring the developments in the marketplace is that a particular technology, RF technology, which is a mesh architecture, has become very robust, very cost effective. It's similar to what my other colleagues are implementing. And we are very interested, and we are trial-ing that as we speak. We're looking to move our network potentially to that if we get

approval from our Commission.

So, we're very excited about the technology movement in this industry in the last. And we like to say at PG&E that we drove that with our 10 million point deployment. So, it was actually Edison, but we like to take some credit for that.

Really the infrastructures are very similar. They all have end points, they all have network equipment, they all have head-end.

What's really important, or that has been developed since California has gotten into this space is the meter data management system, which is the middle ware product that really allows you to put a lot of different data streams into this meter data management system. And then it becomes transparent to your legacy systems, your billing system, your outage system, your asset management system.

All the legacy utility systems can go to one location and get one set of data. And they don't care whether your electric data came from a powerline carrier system or an RF system or what kind of ultimate network you have in the field. It's able to give you data that you can use for

your billing or whatever other legacy activity you have.

So that has been a very important architectural component of the new AMI systems that we've seen in the last five years.

I did want to make a digression here and talk for a minute about deployment because that kind of gets, you know, second shift in the whole evaluation. But there are some very important strategic decisions that need to be made when you go to the physical deployment of your system.

Now, most other utilities don't have quite the geography that we do, but it's still important to think about, you know, whether you want to do it with your own folks, or whether you want a third party to do your installation. There are issues in both of those. Whether a union shop of nonunion shop.

How do you want to realize benefits. We have route strings where a meter reader will read an entire month. They obviously have work every day. And then you want to recognize your benefits when you let the meter reader go. So how you do that, how you construct your benefits realization is important to think about.

And then what geography and what sequencing do you want to do. And specifically for California we were eager to go to the Central Valley because that's where most of our air conditioning load is. We wanted to start there because then we could begin to promote demand response programs. So obviously our deployment began in the Central Valley.

But there's a lot of issues around how you optimize the use of your installers. And that's a really important question to have. And if anyone gets there and needs advice, we have a team of really experienced people who understand the deployment issues. And obviously people helped us, so we're happy to help.

The other thing is that your technology choice shapes how you do your deployment. For example, do you put your end points in first, or your network gear first. And some of that is a decision that you can make. And some of it is important in terms of what technology you've selected, how you do that.

In terms of lead time, if you're hanging gear on powerpoles or light standards, it's important that you get to your cities well in

advance. Now if you're a municipality that's not really an issue. But for us that was really important. It remains important, to get well out in front. And we have a six-month lead time on each of our communities in order to make our first contact before we go to field.

Obviously attachment rights are constantly in flux. And we found things in the field that we obviously had never visited the meter in the last 40 years and someone had built, you know, an entire structure around it. So things were surprising. And we have had to deal with a lot of surprising things in the field. Not significant, but things that we hadn't anticipated. So, enough on that.

So the other thing that's been really exciting, and this has been thrilling for me, personally, because I spent a lot of time in the, you know, four or five years ago looking at the technology space. But things have changed absolutely dramatically in the last three years, or two years, even.

Obviously solid state meters have -- it used to be you buy a little kilowatt hour meter and you buy a huge commercial meter, and the price

points were, you know, $25 and $250.

And now there's something in between that provides a lot of functionality, downloadable firmware, able to collect more information from the meter. Onsite storage, onsite processing capability. Some really exciting things that are going to help us in the future as we develop new programs and offerings for our customers.

Obviously the remote connect/disconnect switches. PG&E, we began our case with a $100 item. And they're, you know, less than half that now. So that's in two years. I mean that is absolutely a fantastic price curve.

And I have this prediction that in five years you can't buy a meter without a disconnect switch, because they're very reasonable; the economics are fantastic. So, if yo do nothing else, that's probably worth doing.

Also the communication networks are very -- the bandwidths are expanding, so that allows you to carry other data like maybe renewables or solar programs, or distribution automation, other distributed generation. All the inhome technologies, it's going to provide bandwidth to communicate to that. It's a very exciting space

right now.

The open architecture, that theme is still squishy because there are a lot of proprietary entities in the market. There are very few that are truly open. And so it's a matter of picking the best thing that's available and making it open on either end so you can get data out of both ends available to a consumer, available to your infrastructure.

And I talked a little bit about mesh technology, which is a really exciting RF, radio frequency, solution that has a lot of -- it's very robust, very scalable, which is really interesting if you're thinking about distribution automation and distributed generation. So you want something that's scalable easily and cheaply expanded the capability. And that's one of the things that I'm really excited about, mesh technology.

And then obviously home area networking. And I think I started down this path, but let me just mention one other thing about emerging standards.

One of the things that's happened with home area networking that I'm most concerned about or interested in, is the issue of security.

Because for the first time we're going to be breaching into the customer's home.

So there's a whole group of people that are working on an open standards body, AMI security, AMI Sec. And they're looking at the end-to-end AMI solutions, and what are the proper security measures to have in place.

So, the industry is very well aware that's an issue and is working actively to come up with some solutions for that.

The good news is I have to stop talking my colleagues will be talking about the same topics, so -- again, this is a repeat of what Tom earlier talked about, which is the home area networking. And, again, it's a very evolving space. We're very excited.

And I think he talked about going and seeing some technology. Well, I went to the consumer electronics show in Las Vegas this year. And it was about half an acre of people, you know, shoulder-to-shoulder, selling product for this very market. It was thrilling.

Lighting guys, security guys, inhome displays, you know, all that equipment that people are really circling and ready to go; Maytag,

Whirlpool, all those vendors are really starting to look closely at the space. And I think it's really evolving.

So one of the things PG&E's been thinking a lot about is this smart grid concept. And really, I agree with Tom, that smart grid, the AMI, and if you talk to anybody in the industry they will tell you AMI is the foundation building block for smart grid.

And the question is what else is it that we have today that we can grow into capability that is better than just a bunch of projects tied together. And there's a lot of discussion about how that's going to evolve, and what we can do as a utility industry to take advantage of some of the technology solutions that are coming into play.

We obviously, we do a lot in distribution automation. We're evolving distributed generation concepts. And those things need to be woven together into a vision of this future that will be. So smart grid isn't just a marketing term, but rather really has some integrated benefits.

So this is just a list of some of the

types of capability. This is the marginal stuff that we don't have recognized in our business case. But I think if someone sat down carefully and looked at each one of these things you might be able to identify things that you could take advantage of in your utility to build your business case. And maybe different utilities have different elements of this that are better for them than others. And it's worth taking a look at them.

I think I've made all these points. So we are on hold at the CPUC for incremental benefits, or incremental hardware, and that's working its way through the Commission this year.

So, I think that's it.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Jana. Other questions?

ASSOCIATE MEMBER ROSENFELD: Yeah. Jana, let me ask you the very question that I said when we looked at Tom Roberts' slide 6. So I'm a residential customer.

MS. COREY: Right.

ASSOCIATE MEMBER ROSENFELD: and I would like some feedback because I am on the internet and I would like to see a display of what I was

using up till an hour ago or so.

Two ways that could happen. I could get it back from PG&E on the internet, but then the meter would have to be pinged more than once a day. Or I could get it directly back to my ZigBee setup for the meter or whatever.

Do you have any idea about which one PG&E would do, and what it might cost extra? Will you have to swap out a meter because most residential meters won't have that facility. And so can you just talk about that for a minute?

MS. COREY: Sure. And let's just presume that our case gets approved at the CPUC and we are putting home area networking devices in every location. So the ability to -- it's a small radio that will communicate into the home.

And what we don't want to be doing is carrying every little bit of data back to PG&E and carrying it on our big pipe. So the communication from the meter into the home is really important. And the open HAN has a standard requirement of ten-second intervals of data going from the HAN into the home.

And the genesis of that is the fact that you want a customer who's got an inhome display,

battery operated. So he's carrying it around his house. Turns off his air conditioner and he can stand there and watch the response.

Now, that's the vision that we all have of how this is going to behave. So if you have an inhome display that will hear the signal from the meter, you should be able to get some information on that kind of a time scale.

Obviously, we have the two paths, which Tom mentioned, which is the website the next day. But the other one is immediate from their home.

And there's a lot of ideas about that, in fact, that are for people who don't have internet. If you have the ability to communicate directly from the meter into the home, they can have a very inexpensive inhome display that gives them that information from the meter, as well. They don't have to have internet to do that.

Does that answer your question, Art?

ASSOCIATE MEMBER ROSENFELD: Yeah. And so you're actually contemplating putting a radio relay on every residential meter?

MS. COREY: That's right. I believe that's not inconsistent with the other utilities, but you can ask them, too. Okay?

ASSOCIATE MEMBER ROSENFELD: Thanks.

MR. HUNGERFORD: Thank you, Jana. I think next we have Paul DeMartini from Southern California Edison.

(Pause.)

ASSOCIATE MEMBER ROSENFELD: While Paul is getting ready I was going to make one annoying comment to Jana. Your slides are wonderful but I wish you guys would quit using yellow on white for the --

(Laughter.)

ASSOCIATE MEMBER ROSENFELD: It doesn't show very well for the audience; and it certainly doesn't show up here.

Good morning, Paul.

MR. DeMARTINI: Good morning. I appreciate the opportunity to share what we're doing at Southern California Edison on the advanced metering infrastructure.

The first slide really tries to highlight a couple of things that we're doing, to answer one of the questions that was asked earlier, which is we do see the Edison's smart connect, which is what we call our advanced metering infrastructure program, is part and

parcel to the smart grid. And as part of the overall solution to meet a number of policy objectives in the state.

One is around renewable and clean generation technologies. Linking with the smart grid through the smart connect to AMI system. What we see with the connected home in terms of, you know, what Jana and David Hungerford and Tom talked about in terms of where we see that evolving, in terms of consumer products, as well as the plug-in electric vehicles that are on the horizon, that in the next couple of years that frankly weren't in our original business case, but is really an upside potential from an overall public policy standpoint.

Bottomline here, the integration of information technology with emerging energy technologies really are going to allow us to achieve a number of very important things here in the state.

Just to set some context, and this is really just on functionality, and I think as Jana's pointed out, I think you'll hear from, you know, Ted Reguly from San Diego, we've all essentially come to the same point in terms of

where the technology is for meter technologies for advanced metering.

We started out with a vision three years ago, and that vision's really come to reality here in the last couple of years. In particular in the last year.

The meter form type that we'll be installing this summer is really the last of the beta versions, if you will. And then we'll be starting deployment in January of 2009, assuming that we get final decision which is scheduled in August of this year.

This just highlights some of the things that you've heard about before. We are looking at two-way communication. We will have the service switch. It does have load limited capability which isn't built into our business case. Which is an opportunity to really put some value on that, as well.

The other is we are looking at the HAN interface. The ZigBee is what we've chosen. We are looking at bridges in the home, though, to home plug command and control. And that's something Jana didn't mention, but ourselves, with San Diego, teamed up on taking the ZigBee profiles

and getting them translated into the home plug command and control standards so that we can have both options, both a powerline carrier option in the home, as well as the ZigBee, so that we can have some very low cost bridging technologies that can go back and forth.

The meters do also have voltage information. And there's some unique functions with the switch when it opens. It will actually sense voltage on the load side and on the line side, so there's some safety capabilities.

And some things that probably, you know, down the road will be able to take a look at with increasingly more distributed generation on the customer's load side.

In terms of overall architecture. Not to different -- I'm sorry?

ASSOCIATE MEMBER ROSENFELD: Can you say, this first bullet of yours, load limiting capability. Can you say a few more words about that? Is this, like is this an agreement with the customer that you get an incentive for green to keep below X amperes? Or you just plain get cut off if you go ahead? A European idea, or is it more sophisticated?

MR. DeMARTINI: In terms of what the program might be, we haven't designed any programs yet. But, --

ASSOCIATE MEMBER ROSENFELD: You just got the hardware?

MR. DeMARTINI: The hardware has that capability that it can be variable. You can remotely set the amperage limit on that switch anywhere from zero to 200 amps remotely. So that you can do something similar to actually a service that Edison offered I think it was 15, 20 years ago called demand subscription service. And you could offer that to customers.

One of the things we do anticipate is the possibility, if we get into a heat storm, and you can sort of virtually see what the loading is on a particular transformer. If you're looking like on the second or third day you're going to get into an overheating potential, that you get on a day-ahead notice. Let people know that you're going to reduce their, you know, the limit on how much load that they can put onto that transformer, such that you could avoid overloading the transformer and avoiding, you know, the transformer to blow.

So there may be some things like that, but it needs more work to look at in terms of what a program design might be.

MR. TUTT: What happens when a customer goes over the amperage limit when you have this program in place? I know you haven't designed it yet, but what actually happens at the house?

MR. DeMARTINI: What would happen is that, what we've talked with the manufacturers about and what we -- actually some other utilities have this, they use it for a variety of reasons.

But what would happen is the switch would open up once you've exceeded the rating. And then it has a timer on it so that it would actually close back in after a certain amount of time so that the customer could turn some things off. And it could go through a cycle of two times or so, reclosing back in before it actually sort of lock out. And then you'd have to reset it.

So, it needs to be explored further. We'd have to look at what the design is and actually need to have a lot of feedback from customers about what would work and make sense. But there is a potential there to take advantage of that functionality.

ASSOCIATE MEMBER ROSENFELD: The point that's tricky, of course, is what you really want to do is differentiate between heavy loads like air conditioners, which are probably on 220 volts, versus very light but important loads like computers which you don't like to have crash.

But I guess that's to be worked out in the next year or so.

MR. DeMARTINI: Actually much farther out. This is --

ASSOCIATE MEMBER ROSENFELD: All right.

(Laughter.)

MR. DeMARTINI: This isn't in the next year or two. This is over the next, you know, three to four years.

ASSOCIATE MEMBER ROSENFELD: Good.

MR. DeMARTINI: In terms of the technology overview, as I said, this is very similar to the slide that you saw Jana present on PG&E.

Again, a multi-tier structure. In terms of the communication network we are using what we call a three-tier structure. We have the home area network, then the local area network, and then wide area network, a back -- solution.

What we did is we, just to give you a little sense of it, the meshing technology. We're looking at a ratio of about 350 meters to a data collector unit. And that isn't the least-cost solution. We didn't design, and did put in our business case, the least cost. We looked at the one that gave us the most flexibility in terms of being able to support many things around the home. And also to have a very robust network, and reduce some of the latency in the number of hops that a meter would take to get back to a data collector unit.

From that point, and we're anticipating there's roughly going to be about 14,000 of these data collectors. From that it would take a public wireless network. We're looking at a cellular right now. But in our business case we did assume that these would be changed out every seven years.

So, every seven years we're expecting the data collector unit to be swapped out. And that's largely based on changes in the wide area network solution. So we're still keeping a pretty sharp eye on developments like WiMax and others as they come along.

And we do anticipate that there is a

possibility, as we're putting deployment out, advances could come must faster than we currently see on the horizon. And it's quite possible we'll migrate from a cellular to one of the emerging sort of broadband wireless technologies that might come about.

And that would allow us to both benefit from on the AMI side, but also potentially for smart grid and mobile workforce automation on our distribution operations.

And then from there it goes into meter data management system. We selected Emeter as our vendor there. And then into a variety of back office applications that are part of this program.

So linking to outage management, a data warehouse, a customer relationship management system, which actually helps us tie into the effectiveness of our demand response and other programs so that we can be more focused in terms of our marketing and a little more efficient in those regards.

A new advanced load control system will be part of, and is part of our application I wanted to highlight. We're starting out with initial kind of out-of-the-box, but we're looking

at much more sophisticated system that'll be coming out to take advantage of the capability of the communicating thermostat that is part of our business case.

We are looking at two different meter vendors, although Itron is the communication. Itron did get the majority of the award, assuming their performance meets expectations.

We are looking at a supply diversity strategy, so our second meter vendor will have approximately 20 percent, which is about a million meters, which is pretty sizeable award.

And we're in the development process with them in terms of an RFP and testing underway in our labs in Westminster.

And we are outsourcing about 85 percent of the meter installs to Corix Utilities. The other 15 percent will be done by Edison personnel.

In terms of the connected home and talking about a power customer choice, we do, as well, see a lot happening in this space. There's a lot of interest in the consumer products area. And I think, as we have been evolving our thinking on this over the last couple of years, -- actually over the past three years since we first came up

with this concept, was the idea that, you know, we've got a lot of interest represented by smart appliance manufacturers.

Obviously the thermostat manufacturers, and other folks that weren't traditionally thermostat oriented like home automation and controls folks that were originally in the home theater business, have moved into this space, recognizing their same technology could enable automated and effective demand response and energy conservation to create an additional value.

In may ways I think they're looking at this as sort of the killer application, because otherwise they were selling convenience. And so now there's an opportunity to really tie into this.

We do see the energy information, you know, driving conservation. And greenhouse gas reductions, by extension. And greenhouse gas reductions were not quantified in our business case, although they were identified.

In our case, for example, we see a 1 percent reduction in energy conservation across our portfolio as a result of energy information. And that would drive about 365,000 metric tons of

greenhouse gas reduction per year on average over the 20-year period. So, potentially, pretty big potential impact.

That 1 percent, according to research that --

ASSOCIATE MEMBER ROSENFELD: Paul, I'm sorry, I want to write it down.

MR. DeMARTINI: Yeah.

ASSOCIATE MEMBER ROSENFELD: By the time the installation program is over you would save how many tons of CO2 per year you're guessing?

MR. DeMARTINI: It's 365,000 metric tons a year. And that's at a 1 percent conservation effect. And the studies that were summarized by Ted Geilen from the Division of Ratepayer Advocates, indicated that the conservation effect, based on largely driven off the near real-time information that's coming right off the meter in the ten-second interval that Jana talked about, and the next day.

But largely driven off the, sort of the Prius effect we call it, of getting the information in real time, is driving that. But the paper suggests the studies, one of them out of Oxford suggested as high as, you know, 5 percent

conservation effect could be achieved. So anywhere from 1 to 5 percent.

PRESIDING MEMBER PFANNENSTIEL: Paul, I just really want to stick with that for a second. On the getting the information to the customer.

MR. DeMARTINI: Um-hum.

PRESIDING MEMBER PFANNENSTIEL: What is your basic model for making sure that the customer gets that information? Real-time information, the next-day information, how were you thinking about that?

MR. DeMARTINI: We have basically four means of getting that information. So start with sort of the traditional. There will be a bill and we will be changing the format on the bill beyond what we have today as the -- you know, we have a newly formatted bill that we have launched here in the last few months.

We are looking to add more information. It won't have all the data, but it will be more informative for those as a sort of base functionality available for the customer.

We will have the information on the website with analytics for next day and historical for 13 months historical. Information for those

that have internet. We are looking at, by the way, the numbers in our area, 75 percent of the customers have internet access --

PRESIDING MEMBER PFANNENSTIEL: I'm sorry, 65?

MR. DeMARTINI: Seventy-five.

PRESIDING MEMBER PFANNENSTIEL: Seventy-five, okay. So it's the last 25 that you need to focus on?

MR. DeMARTINI: It's the last 25. So, then we are looking at really two other forms then. So that's really historical information, either next day or in the case of a bill, you know, the previous month.

In terms of near real time, Commissioner Rosenfeld, to answer your question, we have both right off the meter if somebody has a device that can get that information right off the meter, that's ten seconds, seven to ten seconds. And there the limiting factor is the ZigBee network. The actual meters can go down to five seconds. That's the technical limitation on the meter.

ASSOCIATE MEMBER ROSENFELD: But five seconds is pretty darned noisy anyway, so.

MR. DeMARTINI: Right. So seven to ten

seconds, and ten seconds was what has been adopted, as Jana said, by the open HAN, which is about the time period from the studies that had looked at that suggested that was going to make an impact in terms of the information. So it aligns there.

The other is we do have the ability to do on demand rates. So if a customer calls the call center, they can get the information somewhere between 30 and 45 seconds on demand. So they can either call the call center and get something. Or if they have internet, they can do a on demand read and get something there. And obviously you don't have to be at home to get that information on demand.

MR. TUTT: Paul, --

MR. DeMARTINI: Yes.

MR. TUTT: -- before you go on, you mentioned right off the meter data, and the customer has to have a device to get that. Is it something the customer would buy on the after market in order to be able to get that data, or a service they would subscribe to?

MR. DeMARTINI: It's not a service. This wouldn't be -- there wouldn't be a service

charge for this. What we're looking at is really in terms of inhome displays, what we put out in our business case is three different sort of aspects about how displays might happen.

New construction where the home has a display built in similar to a model that, for example, General Electric has with their EcoMagination where it includes a home automation system, but there is a display integrated in with that, that could communicate with the meter and get the information to be displayed. And they're not the only one, there are others, as well, looking at that.

Retrofit opportunities where there are a number of these home automation control systems. Very sophisticated to very simple technologies, cost effective. Some of which are now becoming available at Best Buy, that could be installed either by the homeowner or through the Geek Squad actually being trained to do that. And those price points have come way down. So that's a possibility that would link in. Which then your tv could be the display unit.

The third is looking at what might look like a memory stick with a ZigBee radio on it that

would plug into a USB drive on your PC at home. Even if you don't have internet, you could still get access right off the meter with a simple little software application that could run.

And we've seen, and we've built into our case, actually, providing some number. And I don't recall off the top of my head, the number of memory sticks that, you know, radios that would be available to customers that we could provide.

That could be taken up in other DR and energy conservation proceedings. And it's being contemplated by the other parts of Edison in terms of other proposals, to take advantage of this.

ASSOCIATE MEMBER ROSENFELD: Let me see if I understood that. The memory stick thought. The meter would communicate with a small radio which would receive the meter information. And load up the memory stick for the last 24 hours of data. And then you'd physically take that and put it in your PC?

MR. DeMARTINI: No, it's not -- it's just the physical size of the memory stick. It's actually a ZigBee radio that would plug into your PC. And then it could turn your PC into a display that --

ASSOCIATE MEMBER ROSENFELD: Got it. That makes better sense, thank you.

MR. DeMARTINI: Yeah, yeah. And it can have an application already loaded on it so when we give it out it would pop up with a very simple, you know, application that could run and provide some display.

If it had internet connectivity then you could obviously do a lot more with it. But even without, it's a way to access the 25 percent that have a PC but don't have internet capability, which there are quite a few of those. But I don't have a specific number on that.

Then we're also working with WiFi router companies who are also very interested in putting ZigBee as part of their WiFi router, so that that would also provide a way, a channel to have somebody's PC get access to the meter.

So we're doing a lot in those areas. Actually doing development work with several of those companies in each of those spaces I just talked about.

On the renewables and energy storage, you know, in terms of solar, I think you know this, but it's an important component to look at

how we can leverage the AMI network to support this, both obviously from net metering, which obviously was one of the requirements; but it does do this.

But also the potential for discrete metering and looking at ways to have separate meters that don't necessarily have to have the same form factor as the revenue meter that we think of today, that can get the measurement and then leverage the communication network so we're not creating multiple networks to be able to link this back to the utility for a variety of reasons, billing and revenue credits and things like that.

But then also the potential to integrate into it integrated energy management around the home. And what we're seeing is that a number of folks that are, you know, with these installations, are pretty sizeable, there's opportunities to have more sophisticated system that also manages load in the home, to align that with the output of the solar panel. And be able to optimize that.

When you start to introduce the potential for stationary, you know, storage through battery technology onsite, then you really

have a potential to really optimize what your system is at the home.

And, again, the meter's providing a whole home sort of feedback loop that in near real time helps to optimize the system. So it's not that the utility's controlling it, actually the home is self-managing, but you need a feedback mechanism and the meter provides that element in that closed loop.

I think you've heard our position on this, but we definitely see the potential of plug-in electric vehicles on the horizon and the battery technology there that seems to be emerging as a great opportunity to take advantage of energy storage. Not the least of which is the ability to have switch from gasoline-driven to potentially these being charged offpeak to take advantage of wind energy and the like. And it, at a minimum, you know, sort of offsets some of the peakiness of our overall grid system for the net benefit of society.

Again, that wasn't something that -- none of what's here is actually in our business case, but these are potentials that have emerged over the last couple of years that we think are

going to be terrific opportunities going forward.

ASSOCIATE MEMBER ROSENFELD: Paul, a comment. I think I've said this in this room before, but probably not to you. Everybody shows this slide with the plug-in hybrid and the charging offpeak.

In terms of actual short-term load management, really short term, there are a few plug-in hybrids right now, and there are lots of ballasts controlling lamps which can be run up and down 10 percent without anybody noticing.

And it will be an interesting thought to think about whether you want to encourage new buildings to have ballasts which have radio control. Those are on the market for daylight harvesting anyway. And with a few more dollars you could have all the ballasts radio controlled, and then you can do regulation up and down via Edison.

It would be interesting to talk about that economics, too.

MR. DeMARTINI: Right. And that really goes back, you know, back to this concept, and this is just the home. But certainly in the commercial space there are lots of opportunities

to take advantage of. Discretionary loads that may not be optimized to your point that we could start to look at.

And it may not be the air conditioners, the first thing, although that's big user. There are other applications that, as we start to get into this, the consumers may be able to pick their own sort of dispatch profile based on comfort. But also being able to realize the net reduction in demand that we want.

And that's where I think this is really starting to get pretty exciting, is that we can really look at how to tap into this and make it convenient, and in some cases automated.

ASSOCIATE MEMBER ROSENFELD: Right.

MR. DeMARTINI: Just wanted to provide some context, a little more, about how we see this evolving with the smart grid. And you can see that from one end with the customer it's clearly something that we see coming over the next decade, is increasingly and starting very soon with automated, our advanced metering infrastructure, is the engagement of customers in a different way than we have in the past. And really becoming a partner in helping manage the supply chain to, you

know, to the effect that we're all trying to drive towards.

We do see emerging technologies in these green bars going across the bottom. And as that, you know, as part and parcel with that, you know, the smart sensors and controls, and in some ways we look at the meter as a smart sensor on the grid.

And then, you know, the communication networks we've talked about. Operational systems, many of which were highlighted on the other. The customer and operational data warehouse, you know, Jana talked about this, it's really important. This is going to be the hub of a lot of information that's available for, you know, outage management, sure, but also from system planning and management and grid optimization in terms of understanding what's going on, you know, in near real time, or in some cases real time, what's happening on the grid and how do we manage this.

Because as we look at more intermittent resources on the grid, both at the sort of the central plant kind of concept or scale, but also increasingly more on a distributed smaller scale, the ability to manage this so that we have a

stable network is going to be really important.

And that's really where predictive analytics and other analysis tools like our phaser measurement program, which I believe you probably heard from Mike Montoya, talking about some of the work that we're doing in there, really comes into play.

And actually being able to achieve a number of these things that are highlighted in the yellow box in terms of customer choice, improving overall performance, efficiency and supporting the clean energy objectives that we have in the state.

In terms of cost/benefit analysis, this is the cost/benefit analysis that is before the Commission at the moment. This was based on the settlement that we have with DRA. And partial settlement with TURN. TURN had some outstanding issues on demand response. But in terms of cost, and the operational benefits and conservation, they agreed with these figures.

In terms of overall benefit you'll see that, not including societal benefits, based on the settlement, were just marginally positive, essentially break-even. But when you add in the net societal benefits to your point about the

municipal utilities or others, these would accrue to them.

The societal benefits we included here were actually two benefits of one cost. One of the benefits was improved meter accuracy, which essentially technical losses and theft with nontechnical losses. But then we also included the additional usage that the solid state meters have over the old electromechanical. So there's a little increase in consumption. And so that netted out to $295 million on present value revenue requirement.

So, if you looked at it from that perspective, which a municipal utility might look at, the case becomes quite a bit more positive. Certainly, as other utilities and other jurisdictions, they were able to capture those benefits. And this would be a similar case that they could make in their area.

And you can see the breakdown in terms of where we see the various benefits. Actually a big part of it is price response and load control. The load control comes from the smart thermostat programs we're proposing for both new construction and our existing customers.

And then the energy conservation benefit that I mentioned earlier is worth $164 million in present value terms.

ASSOCIATE MEMBER ROSENFELD: Paul, the line between price response and load control is very fuzzy in my mind. To my mind they could all be called load control or they could all be called price response. Can you say a few words about that?

MR. DeMARTINI: And you're right. It's almost three categories, if you will, not just two. So there are some elements of our case that are pure price response, not taking into account load control. That is, you know, we sent out a pricing signal and through critical peak price or peak time rebate, and customers do something behind the scenes, and they respond in one way or another to that. So that's sort of in its purest form, sort of, you know, theoretically.

On the load control there is an element that looks at load control without any pricing signals on some, you know, theoretical basis, and somebody's responding to incentives to respond to a load control, or it's an automated based on a voluntary program that they would have signed up

for.

But there's a lot in between in our case where we've actually linked pay for performance around load control with a pricing. And a good example of that is our peak time rebate.

What we've suggested is, and this is still, you know, going through at the Commission. I believe we've already filed with the -- our GRC phase two, in terms of peak time rebate, $1.25 a kilowatt hour if you have enabling technology which would tie into the load control, or at least how a lot of folks think about that traditionally. But 75 cents a kilowatt hour if you don't.

So, we've tried to link these so that there's more alignment. And we did, in the case, take out any overlaps between the two. So we did a lot of work to -- and again, sort of blurs the line between load control and price response, so that there is no overlap, because we're assuming that people are going to do both to take advantage of it.

ASSOCIATE MEMBER ROSENFELD: Okay.

MR. DeMARTINI: Part of what we did with the load control, just for background, is so that you could help folks get -- help understand where

the costs were associated with thermostats and the like, and other systems that went behind that versus the benefits. Because people were trying to understand the cost/benefit of those elements.

In terms of deployment plan, I apologize, this has yellow on the slide. Just to highlight the years in the deployment.

This is a busy chart, but it kind of illustrates the complexity of what we're doing concurrently. That is, those lines at the top represent the software functionality that we're installing concurrent with the meter installs, which is the curve at the bottom.

And all of that has to converge at certain points. And these releases are organized around taking the whole of the functionality that we talk about for this system and breaking it up into logical chunks of work that we can deploy in a way that allows us to build a foundation. And then add additional functionality along the way in a way that allows us to manage the risk in a logical form, to allow us to complete one piece, you know, as we -- and then roll in the next one coming on.

And you can see down below in the text

some of the functionality as it rolls out over time.

In many ways, and I think Jana touched on this, we're changing fundamentally the way that we, you know, interact with our customers. And these systems will fundamentally change the customer experience, we believe, to significant benefit, which again aren't in the case in terms of customer satisfaction.

One of the things that we see kind of goes to a question that Commissioner Pfannenstiel asked, is we see a bi push toward self-serve. The customers are looking to do more on their own. Certainly as a new generation of consumers come into the marketplace, they're used to doing things via the net, whether it's on a PC or whether it's on a PDA or an iphone or the like.

And so we're needing to evolve to that. And these systems already allow us to be able to provide the information the way that works best for them, including messages that, you know, wouldn't just go to a meter, but also go to their handheld devices or however they prefer to get them. So, lots of different ways are emerging that we expect to be able to support.

I think that's my last slide.

PRESIDING MEMBER PFANNENSTIEL: Thanks, Paul. We clearly have delayed, gotten in the way of moving this on the way David Hungerford had thought we were going to be scheduling. But, very very useful information.

Should we move on to SDG&E now before we break for lunch, and then perhaps after lunch we can get the three investor-owned utilities back for the panel.

MR. HUNGERFORD: We have Ted Reguly from SDG&E with us today.

MR. REGULY: Thank you, David. Hopefully this will be short. I want to thank Tom, Jana and Paul for really going into quite a bit of details about AMI and how it supports the smart grid and the home area network. So I'm not going to dwell on that very long at all.

Do want to answer some questions, though. We are definitely looking at both gas and electric, because we are combined utility. We are also looking at water. And to Commissioner Rosenfeld's comment, we do see a sweet spot between gas, electricity and water, especially in the home for the inhome display and other ways, to

get that information to the customer.

And it's interesting, I've been involved in this three years, and it really got started in the electric side of the business. But you can really see it growing in the gas side. And I was actually at a water conference where with water conservation this seems to be getting very popular, not only in California, but throughout the United States.

ASSOCIATE MEMBER ROSENFELD: So, Ted, does that mean on the water meter or gas meter information you'll have more closer to real time than once every 24 hours?

MR. REGULY: Yes. That's really the benefit of the home area network.

ASSOCIATE MEMBER ROSENFELD: Good. Thanks.

MR. REGULY: We are looking at all of San Diego County and the southern part of Orange County where we provide electric service.

Like Paul was mentioning, we really do feel this to enhance customer service through better information. And also, we're seeing our customers also wanting to go towards self service.

We do see it as foundational for the

smart grid, and we did show a positive business case.

What I'm going to go through here is a little bit more about the process we went through in developing the business case. We think it was a very systematic process. We did start not with the technology, but we started with the benefits that we wanted to achieve.

From that we came up with the functional requirements that were needed from the system. We then took those functional requirements, wrote detailed technical specifications and took it to the market and saw what the vendor community could do to meet those requirements.

What we had to do, and this was probably the most challenging part of the whole solution implementation, is to bring our subject matter experts into a room and try to explain to them what the world would be in an AMI-enabled world.

This is very difficult with individuals because they have a tendency they want to see it, they want to go out and visit it before they can embrace it. And with AMI there is not a whole bunch of utilities in the United States where you can go and actually see this working.

Very high IT part of the project. And we, as part of this project, did not want to look at just the first cost of the project. We wanted to look at the total cost of ownership, and that's how we evaluated our business case.

Vendor solicitation. We did take these business and functional requirements, put them into a five-part RFP. Took that out to the marketplace and got responses. As part of our risk assessment, when we went through actually our hearings with the PUC, we did not have our AMI solution picked at that time.

We're currently negotiating contracts on that right now. And one of the reasons why we did not was because that is such a high, it's about two-thirds of the cost of the project. And as Paul and Tom and Jana have mentioned in the past, we had seen significant investments in that. And so we wanted to delay that decision until we're getting ready for deployment. So we're actually in the process of finalizing those contracts as we speak today.

After we -- before we actually got the RFPs back, we then went back and decided how we were going to evaluate them, how we were going to

score them, and how we were going to risk-adjust those scores. We then pulled that into our total cost of ownership, and that's how we made our selection.

Another big part of this project is coming up with a solution architecture. I think Paul showed it on his slide. What we were really considering is we wanted something that embraces open standards, something that was upgradable. Something that had a long life.

This slide here just basically -- this was back in 2005 and 2006 when we went out for our RFP. It took us about eight months from beginning to end of the process. After we did get a favorable decision from the PUC last April, we did go back out to market for the AMI technology piece. And that was to incorporate the integrated remote disconnect and the home area network.

This is just a list of the initial benefit sessions. As you can see, it touches almost every area of your company. So, it's very time intensive, and you really need to bring all the business owners in so that they can fully understand what the benefits of a system like this could be for them.

We actually went through business process design sessions. You can see the list of these where we actually went through, and we said, this is how we do the business today; this is how we're going to do it in the future. And that helped us drive what the system needed to do to achieve those benefits.

Just more benefits, more BPD sessions that we went through.

This is what we came up with. I think Tom hit this. Solid state, electric meters. We are actually, for us, our AMI solution is going to be for all our customers. So all our C&I, all our residential will have the new solid state meters. We will have a remote disconnect for residential customers, 200 amps and less. We are planning to incorporate the home area network chip in all our meters, even our large C&I meters.

Interfacing with load control. PCTs or other load management devices for our small C&I customers. And we are trying to stay vendor and technology neutral as part of this process.

Go through and just talks about -- this slide talks about the benefit categories, what our current state is, and what our future state is

with AMI. From this list you can see it's not only meter reading, and even demand response. There's a lot of other benefits that you can get from an AMI system.

Where we're at right now is we are currently in the build phase for all our IT systems. We're planning to finish that in and around February of next year.

Currently we're in the process of rolling out around 5000 meters in the Tierrasanta area of San Diego to test the technology. Then beginning in 2009 and 2010 we'll actually be installing the majority of the meters. And then in 2011 we'll be actually ramping the wrap-up and turning the system over to the various business units.

This goes through month by month meter installation. During this timeframe we'll be installing about 5000 meters a day throughout our service territory.

And last, but not least, the home area network slide, I think you've seen it at least four times or three times ahead of this. We do plan for the meter via the home area network to communicate in the home. Not only for helping the

customer control load, but as Paul mentioned before, is for distributed load, or distributed generation like plug-in hybrids, solar, to actually make those dispatchable.

And vis-a-vis our peak time rebate that we're proposing. Actually someone that can put energy on the grid during a peak day, being a peak time, will actually get incentive to do that at 75 cents per kilowatt hour.

So I do agree with others that this really fits in with renewables, smart grid, and is foundational for California.

And I think that's it. Any questions?

ASSOCIATE MEMBER ROSENFELD: Yeah, Ted. If I live in Bakersfield and I have solar on my roof, --

MR. REGULY: Yes.

ASSOCIATE MEMBER ROSENFELD: -- and you have time-of-use pricing built into your peak time rebate. Then did you say that I can sell back to the utility at time-of-use rates plus 75 cents a kilowatt hour?

MR. REGULY: Well, what I'm talking about is what's called our peak time rebate, which is for our residential customers. And the way

that works is it calculates a baseline, three of your five last like days. And if you either conserve, if you don't, let's say, have a distributed generation, less than that on a peak day you'll get the 75 cents.

But the nice thing about like solar is if you generate, and that actually -- because normally solar on a lot of houses during the peak time, they're not using electricity. They're putting electricity back on the grid. So if they put more electricity back on the grid during let's say the 11:00 to 6:00 timeframe, they'll get the 75 cents per kilowatt hour for that energy they put back on the grid.

ASSOCIATE MEMBER ROSENFELD: Right, and I think I didn't phrase my question comprehensively.

MR. REGULY: Oh, I'm sorry.

ASSOCIATE MEMBER ROSENFELD: Your rebate tariff includes time-of-use on every weekday afternoon?

MR. REGULY: It's a time-of-use every week -- it works on weekends and holidays. It's just your baseline is calculated differently on a weekend or a holiday than a weekday.

ASSOCIATE MEMBER ROSENFELD: Okay. I'll catch you at lunchtime.

MR. REGULY: Okay.

PRESIDING MEMBER PFANNENSTIEL: We are going to have a session, I think, next session on rates on the load management standard, which, I think, will be really useful.

Any other questions for Ted? You did get off easy because the hard questions were arguably before.

I think we should break now for lunch. And back here, I'm going to say at 1:15. I have a luncheon meeting, and I'll be back by then.

Thank you.

(Whereupon, at 11:59 a.m., the workshop was adjourned, to reconvene at 1:15 p.m., this same day.)

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AFTERNOON SESSION

1:20 p.m.

PRESIDING MEMBER PFANNENSTIEL: We had thought that we would have the investor-owned utility representatives come together in a panel, but I'm not sure we actually need that at this point. I think that we've beat them up enough with our questions so far.

I'm hoping that if they stay around and other questions may well come up in the afternoon that we may refer back to your earlier presentations.

But with that, let's move on to the publicly owned utility panel. David.

MR. HUNGERFORD: All right, we're going to do the publicly owned utility panel in the same way that we did the investor-owned utility panel, where we have just a random order of speakers. And then we'll run questions during the presentations.

And so, Craig Kuennen -- I pronounce that correctly?

MR. KUENNEN: Kuennen.

MR. HUNGERFORD: That's right, Glendale

Water and Power will start; followed by George Chen of LADWP and Erik Krause of SMUD.

So, get to your presentation.

(Pause.)

MR. KUENNEN: My name is Craig Kuennen; I'm Marketing Manager with Glendale Water and Power. And I'm actually here to give a brief overview of SCPPA member AMI activities. That's the Southern California Public Power Authority.

The first one I'll cover real quick is Anaheim Public Utilities. Basically they're initiating AMI residential deployments in June with approximately 220 meters. Their plan is to install 3000 to 5000 meters per year for the next few years.

They're going to be evaluating their installation and the benefits and costs over that time. And then they'll make a decision whether to accelerate the deployment.

PRESIDING MEMBER PFANNENSTIEL: Can you tell me how many residential customers Anaheim has?

MR. KUENNEN: I don't know that total.

PRESIDING MEMBER PFANNENSTIEL: So we don't know, you know, 5000 meters a year, so you

end up with 10,000 meters --

MR. KUENNEN: I can get whatever --

PRESIDING MEMBER PFANNENSTIEL: Is that a small percentage or large percentage is what I'm kind of looking at.

MR. KUENNEN: Yeah. I don't have that information, --

PRESIDING MEMBER PFANNENSTIEL: Okay.

MR. KUENNEN: -- but I'll get that for you.

PRESIDING MEMBER PFANNENSTIEL: We can get it. Thanks.

MR. KUENNEN: Their system is going to be a two-way hybrid system. They're working with Tannalis (phonetic).

In Burbank they're committed to doing a smart grid using a wifi technology. And they're working with SmartSynch and Tropos networks to do that.

The drivers behind the technology, they want to provide information for the customer and meet their power supply needs, more than just looking at reducing meter reading costs.

They want to facilitate a set of programs that reduce their peak load; coordinate

the demand control operations across the commercial base; improve system efficiency and identify candidates for conservation improvements.

The initial citywide wifi will be done, they're looking at the first quarter of 2009. Their plan is to have their smart grid by 2012. They see AMI, basically they're going to target their large customers first. They're about 50 percent of their sales. And they're hoping to have those done by the end of next year.

In other benefits, they're looking at meter data management system installation, cyber security, outage management system, smart grid capable, interactive voice response system, demand control coordination. Thermal storage with HVAC systems. I think that's the ICE Bear technology that they're working with. And deliver demand response and load management benefits.

In Glendale we reported last month --

ASSOCIATE MEMBER ROSENFELD: Whoa --

MR. KUENNEN: I'm sorry.

ASSOCIATE MEMBER ROSENFELD: -- whoa. What on earth is voice response system?

MR. KUENNEN: When customers call in they get the IVR, which is an automated answering

of the phone giving different options to have their questions answered.

I don't -- I'm presenting what they gave me, so I would have to go back and --

(Laughter.)

MR. KUENNEN: -- get the answer to how that's supposed to work.

ASSOCIATE MEMBER ROSENFELD: Okay, that's an honest answer. Thank you.

PRESIDING MEMBER PFANNENSTIEL: But they are going to be moving towards a smart grid --

MR. KUENNEN: Yes.

PRESIDING MEMBER PFANNENSTIEL: -- by 2012. But without advanced meters?

MR. KUENNEN: Well, from my understanding with Burbank is they're going to have the AMI, but they're going to use the wifi to do the backhaul the information. So.

PRESIDING MEMBER PFANNENSTIEL: But for residential -- I mean they're going to put smart meters obviously on larger customers, --

MR. KUENNEN: Right.

PRESIDING MEMBER PFANNENSTIEL: -- but for residential customers they're going to have a smart grid system, but they're not going to have

that information at the customer level?

MR. KUENNEN: No, well, not at this time, they didn't give me that information --

PRESIDING MEMBER PFANNENSTIEL: Okay, I'm not sure --

MR. KUENNEN: -- as far as what they're doing with residential.

PRESIDING MEMBER PFANNENSTIEL: -- how it works. Okay, thanks.

MR. KUENNEN: They're going to target the largest customers first, put the infrastructure in. And then I would think move on to the residential, but --

At Glendale we reported last month that we started with AMR. Our water department is looking to do AMI regardless of what our business case looks like, because for them it's positive already the way they look at it.

We see the smart grid as the way of the future. And AMI is the first step in that process. As I reported last month, we contracted with KEMA to help us do the AMI plan and development. That's going really well.

We're still on schedule to complete our business case by July. And then we're planning on

moving on with the selection of -- issue an RFP and selecting the vendor by October.

Our concerns were, they're being addressed through this workshop as far as standard communication protocol, to allow for various interchangeable meters and inhome energy saving and demand response technology.

We need to find a single system that supports AMI for electric and water. That was a question, I guess, that was brought up earlier. It doesn't make any --

ASSOCIATE MEMBER ROSENFELD: But I'm surprised you don't say electric, gas and water.

MR. REGULY: Well, we're an electric and water utility. We would gladly work with the gas company. They're not here. I don't know why they're not participating.

ASSOCIATE MEMBER ROSENFELD: Well, you don't have to meet them in Sacramento.

MR. REGULY: Oh, okay. I just see the electric company's here, that's it. But we would gladly work with the gas company.

MR. SPEAKER: The gas company's actually here.

MR. REGULY: Oh, are you?

MR. SPEAKER: We're glad to work with you.

MR. REGULY: Okay, --

(Laughter.)

MR. REGULY: Well, then I got a card here for you.

PRESIDING MEMBER PFANNENSTIEL: Here we go.

(Laughter.)

ASSOCIATE MEMBER ROSENFELD: Okay, you did meet in Sacramento.

MR. REGULY: Okay. Had to come all the way up here to meet you.

MR. SPEAKER: We'll talk offline.

MR. REGULY: Okay.

And as I mentioned before, as the IOUs start installing these on a regular basis, we're worried about inventory for meters and the other technologies that go along with it.

Do you want to come on on this part? Cool. Excellent.

MS. BRETZ: My name is Cathy Bretz and I work for the Imperial Irrigation District. I'm the Manager of Customer Operations.

So, I can hopefully give you some more

detail as we go through these slides. IID does see AMI as an integral component of its customer relations management initiative.

The goal is to improve operations efficiency and customer service through technological improvement and increased customer rate choices. And we are evaluating a variety of AMI solutions now before moving forward to full scale implementation.

We have one city that has completely been converted to TWAX DCSI. We have a fixed network, and we also have what I call the low-hanging fruit, and that is the radio frequency metering.

We've installed 334 IP interval meters at commercial and industrial sites. Our commercial customers are mostly gambling casinos. So it doesn't get much larger than that in our area.

Okay, Imperial Irrigation has installed an enterprise wide radio frequency solution over an existing 800 megahertz data network for five commercial and industrial customers. We've installed over 1200 neighborhood wide radio frequency ERT meters.

And it's an ongoing process for the new residential construction. What IID chose to do is, as we were experiencing an 8 percent growth per year of residential and commercial customers, we opted to make all new installations ERT meters, and pass the additional cost of the meters on to the developers.

And so during that period of time we were able to saturate 12 percent of our customer base with ERT meters.

And then we've installed the powerline carrier DCIS TWAX as a pilot for approximately 750 meters. And of those, 200 are small commercial and the rest are residential.

And that's all for me unless you have questions.

PRESIDING MEMBER PFANNENSTIEL: Are you planning to do a full saturation of residential customers?

MS. BRETZ: The way that I'm approaching it for our company is we have not done routine meter maintenance in over 20 years, so approximately 80 percent of our meters are over 20 years old. So we are going o do it as budget allows on retrofit.

And what we look at when we put an ERT meter in is we decide one, if the area can be put into a fixed network; whether that would be the lowest cost, or whether we're going to be cutting down on windshield time.

We have one area that's called Winterhaven that is right on the Arizona border. And so it takes us an hour and 40 minutes to drive there.

So if we can even do an ERT solution instead of sending six meter readers out, we're sending one. So, we're looking at each one in a different situation to see what the best solution would be.

PRESIDING MEMBER PFANNENSTIEL: Have you done a business case, looking at replacing all of your meters with some variation of a smart meter?

MS. BRETZ: No, we haven't. Simply because we would have to raise our rates to do that.

PRESIDING MEMBER PFANNENSTIEL: To do the business case?

MS. BRETZ: No. The business case has been done. And to replace the meters we would have to raise our rates, and that is just not in

the foreseeable future.

PRESIDING MEMBER PFANNENSTIEL: But you say you have done the business case?

MS. BRETZ: Yes.

PRESIDING MEMBER PFANNENSTIEL: So you have done the analysis, --

MS. BRETZ: Yes.

PRESIDING MEMBER PFANNENSTIEL: -- and unlike the investor-owned utilities, your analysis showed that it would not be cost effective for the company to replace all of the meters?

MS. BRETZ: No. We're actually, our criteria right now for replacing a meter is one, has it passed the 15-year mark; two, if it has been a meter that we put in in the last five years, and it's a digital meter, we can send it back to Itron and have it retrofit for a nominal cost. And then, three, to cut down on the windshield time.

PRESIDING MEMBER PFANNENSTIEL: Can you provide us with a copy of the business case?

MS. BRETZ: Sure.

PRESIDING MEMBER PFANNENSTIEL: Thank you.

MS. BRETZ: Okay.

ASSOCIATE MEMBER ROSENFELD: Could you say a word more about that? We heard a string of talks this morning in which, for the biggies, for the IOUs, the business case paid, and so your rates wouldn't go up -- would go down.

What's sort of different about your case, IID?

MS. BRETZ: For us it's just the cost of the meters. If you look at we haven't replaced meters in over 20 years. Going out and doing 145,000 meters at once is just going to be a huge cost for us to lay out --

ASSOCIATE MEMBER ROSENFELD: But the IOUs had to replace the meters, too, and their business case came out favorable.

MS. BRETZ: But we don't incur any cost if we do it on a slow implementation. Because we still are allowed to do the depreciation of the meters and then we are still allowed to forward and gain efficiencies in the routes as we move forward.

And at the same time, like I said, we've got three pilots going right now. And we're looking at the pilots to say what is the best way that we need to move forward.

PRESIDING MEMBER PFANNENSTIEL: But you will send us a copy of your business case so we can understand --

MS. BRETZ: Yes.

PRESIDING MEMBER PFANNENSTIEL: -- why it came out that way?

MS. BRETZ: Yes.

MR. TUTT: And do the ERT meters have similar functionality to the meters that the utilities are rolling out or installing?

MS. BRETZ: Yes, the ERTs are the radio frequencies.

ASSOCIATE MEMBER ROSENFELD: Have a what?

MS. BRETZ: Radio frequency.

MR. TUTT: The remote connect and disconnect and all of that?

MS. BRETZ: No, we don't -- we have piloted some remote connect and disconnect in the Nyland area with the TWAX system. But what we're finding is that the customers' panel boxes in this area are too old to accommodate the additional collar that it takes to put on the meter.

So, that's kind of fallen by the way. It becomes a secondary. So, that is part of an

efficiency that we can't gain at the moment.

Thank you.

MR. KUENNEN: Thank you. The last one is Pasadena Water and Power. They're in the final stages in an AMR implementation. So that's just the one-way technology; it's not AMI.

They're scheduled to be done in the next two to three years; they're about 70 percent complete on residential, and 100 percent on commercial.

Their challenge is this large investment in AMR makes it hard to switch to AMI at this point. And they're looking how to treat that investment and to recover that before they move on.

They do like the idea of the smart grid. They see it as promising. They do have a fiber ring in place in Pasadena that could facilitate that. And their service territory is such that it would lend well to a smart grid.

They're looking at preliminary AMI options. They're forming teams to develop the business case. They're seeking consultants to assess their infrastructure. And they're working with EPRI on the intelligrid and advanced

distribution automation programs.

In terms of what they're looking, in terms of protocols, they would like to see standing protocols for functionality, but allow utility discretion on how to or when to implement the AMI.

They agree that all utilities should be encouraged to do business cases on AMI. And like I mentioned, their concern is how do they recoup the costs of the AMR that they're just installing or just completing.

And that was it. So, thank you for the opportunity --

PRESIDING MEMBER PFANNENSTIEL: Can you help me understand what the functionality difference is between the AMR and the AMI is that you're talking about here?

MR. KUENNEN: Well, my understanding is the AMR is the old technology. It's one way. You can read the meter, but you can't do --

PRESIDING MEMBER PFANNENSTIEL: So, today it's just the one-way --

MR. KUENNEN: -- education with the customers --

PRESIDING MEMBER PFANNENSTIEL: --

technology?

MR. KUENNEN: -- you can't push out real time pricing. You can't do all the things that get you the benefits that we don't even know what they are right now, but --

PRESIDING MEMBER PFANNENSTIEL: I see. And are, those new meters that they're putting in, are they adaptable to an AMI?

MR. KUENNEN: It's my --

PRESIDING MEMBER PFANNENSTIEL: Or do they have to take them out and throw them away and put in a new one?

MR. KUENNEN: It's my understanding you have to take them out and throw them away. The AMR is not -- you can't -- everything I've heard you can't retrofit.

ASSOCIATE MEMBER ROSENFELD: Well, I'm sorry, I'm getting confused now. EMR is a brand name?

PRESIDING MEMBER PFANNENSTIEL: AMR.

MR. TUTT: AMR.

ASSOCIATE MEMBER ROSENFELD: No, AMR I know, but --

MR. KUENNEN: AMR, it's --

ASSOCIATE MEMBER ROSENFELD: I thought

you said EMR just now.

MR. KUENNEN: No, AMR. I'm sorry.

ASSOCIATE MEMBER ROSENFELD: Okay. Sorry.

PRESIDING MEMBER PFANNENSTIEL: Thank you.

MR. HUNGERFORD: All right, now we have George Chen from LADWP.

MR. CHEN: Thank you, David, and Commissioners. I'm going to just go over our AMI plan, -- did some of these last week, and this time we just add a little bit more and hopefully we can answer your question.

Okay, our AMI implementation strategy is that we plan to have an open, nonproprietary communications, and also very, you know, easy to interchange in the future. And we also like to have device that can be just plug and play.

Also we like to minimize the impact of communication technology changes so that we can install some kind of network that will help us less IT work. And also we'd like to implement that program, the home, you know, energy management system in the future. And hopefully those devices are going to be off the shelf.

And lastly, we like to develop, design a flexible AMI smart grid foundation for future technology, standard system interface in the regulatory requirements.

Okay, we have currently a five-year plan. We have two technology approach. On the high end for the commercial customers we using two-way communication system. And use public communication network to transmit the data back to the office.

And last time I think the CEC help us start it for the 200 kW up, and now we like to move that technology down to about 30 kW so that will cover all the medium to large commercial customers. I think that's pretty, you know, easy system to operate. And we will get all this latest technology, you know, high users.

And we also looking at about those homes that 64,000 initial customers. They have monthly consumption over 1200 kWh. We think that there's a lot of, you know, room for us to do some home energy management there.

And also we see about 10,000 customers constantly moving in and out; those are dormitories and apartments that have high turnover

frequency. So we think that's the place for us to install some remote turn-on/turn-off.

And lastly, we have about 2500 critical care residential customers that we need to constantly watch. So those are the high-end meter service issues.

And the rest we have about 1.2 million electrical meters that we think we're going to use ERT technology. The previous speakers that help us to, you know, discuss about the meters that it's easy to install. You can just plug it in. And the function is only AMR, so they just automatic meter reading. So help us to read the meter easier. And gain some efficiency. That's not much, you know, control going on at current state. That will, you know, also save some time for us to get information back.

And we also transfer the water ERT so we connect all the water meters.

PRESIDING MEMBER PFANNENSTIEL: So, let's just make sure I understand.

MR. CHEN: Sure.

PRESIDING MEMBER PFANNENSTIEL: So there are about 77,000 residential meters that you'll put --

MR. CHEN: Two-way communication.

PRESIDING MEMBER PFANNENSTIEL: -- two-way communication. And those would be ones that you identified above.

MR. CHEN: Right.

PRESIDING MEMBER PFANNENSTIEL: And then the remainder of your customers, residential customers, --

MR. CHEN: Yes.

PRESIDING MEMBER PFANNENSTIEL: -- and small commercial, you'll phase in these, essentially meter reading ones, AMR.

MR. CHEN: Yes. So prior sometime, we also waiting for the technology to develop, and waiting for the price coming down. So right now, you know, I hear, you know, there's a lot of business case for that. But I may ask a question later on about IOUs, how they foresee the future.

But what we thinking that right now give us some time with ERT meter; these are small homes. The usage -- the average usage about 300 to 500 kWh. And honestly, they don't use the air conditioning or other devices much, so we think, well, at current state that this is probably the most, you know, cost effective way to approach

them.

But later on we can talk about these. And I have some ideas listening to the IOUs. And I think there's some exciting -- coming out.

PRESIDING MEMBER PFANNENSTIEL: But you will be putting new meters on these homes?

MR. CHEN: Yes, the ERT meters.

PRESIDING MEMBER PFANNENSTIEL: Right.

MR. CHEN: Right.

PRESIDING MEMBER PFANNENSTIEL: But then there becomes the question of the increment from the new ERT meters and the more sophisticated two-way communication meters.

MR. CHEN: Right.

PRESIDING MEMBER PFANNENSTIEL: I don't know what that difference is, but --

MR. CHEN: Well, the difference, I think right now you talk about, you know, the regular mechanical meters, on average about $25. And if you added the ERT meter, that's about $40. And I just heard the IOUs, Edison, talk about this morning $4 billion, 16 million meters. That quick math tell me about $200 per point.

Maybe I'm wrong --

PRESIDING MEMBER PFANNENSTIEL: Is that

the --

MR. CHEN: So, so --

PRESIDING MEMBER PFANNENSTIEL: Well, would you just come up to the mike? About what would you average a meter? I think you need to come to the mike, if you would, please. I know it's hard because there is a systems in there, but what --

MR. DeMARTINI: Setting the systems aside, just to be on an apples-to-apples, what's being described is under $100.

PRESIDING MEMBER PFANNENSTIEL: Okay, thank you.

ASSOCIATE MEMBER ROSENFELD: I'm sorry, Paul, I'm not sure. Could you say between the two of you what an ERT meter does, and just amplify a little bit?

MR. DeMARTINI: An ERT meter is, typically these days it's a solid state meter relatively simple; it's a technology that's been around for ten years or so. We have 600,000 of them, ourselves, that's why our case wasn't as positive the first time around.

And you can either walk by or drive by and pick up the signal. It's a one-way

broadcasting signal that you can pick up and read the meters for meter-reading efficiency is --

PRESIDING MEMBER PFANNENSTIEL: So it's not remote meter reading, but it's --

MR. DeMARTINI: No, and there's --

PRESIDING MEMBER PFANNENSTIEL: -- easier than --

MR. DeMARTINI: -- variations that allow you to put a network in, that you could have a fixed network to pick it up. But it's really for meter reading efficiency.

ASSOCIATE MEMBER ROSENFELD: So it's in no way an hourly meter?

MR. DeMARTINI: No. It's typically a cumulative --

PRESIDING MEMBER PFANNENSTIEL: It's just a monthly meter?

MR. DeMARTINI: -- read --

MR. CHEN: No. If you put a network in there you can get all what it reads.

PRESIDING MEMBER PFANNENSTIEL: Are you planning to?

MR. CHEN: In the business case we talk about there's a flexibility there. If we required it to get interval data, get the time-of-use

information, we will. But if we're not required at this time, we won't. So, we can't, you know, drive by or walk by.

And once in that, you know, really, Edison and the IOUs talk about it, we think the increment cost is not that big issue for us. Honestly, even to $20 per meter for residential, if that's all the costs, you know, in one, we will do it.

The problem comes in that how you manage the network, how do you get the data, what do you do with the data. Those are things that we don't have a solution yet.

And I probably kind of -- when I go in that, we can talk about this, because the increment cost is not the issue here. It's the issues of management and how you, you know, have the IT support. All this information coming and how to get the data and keep up with the technology. That's the challenge here.

I mean putting network is okay, but -- we can do it, we just don't know what to do after that.

Okay. You know, benefits, AMI. We see it; remote turn-on/turn-off, that will help us,

you know, also fighting crime. And tentative metered building for the large customers, they'd like to have these so that can synchronize with the accounting system.

Again, improved safety. Right now the AMI will help us, you know, the ERT meter, we don't have to go into the backyard to face the dog again, and all these other issues. We can drive by or walk by.

Again, special rates. So our high end customers getting all the bells and whistles on these so we can do all these critical peaking, net metering, load curtailment, all these we'd be able to do with our large customers.

This, you know, a little bit different approach, I think I mentioned last time. We looking at the interruptible rate on the large customer. And especially those code -- customers. And we'd like to have this customer help us out when we have a power crunch and statewide, you know, issues that we can ask them to turn on their generators for us. They we giving them some kind of benefit on the rates.

And we have, in our territory we have about 200 to 300 megawatt generation already

exists. So, if we can make these guys happy with us, that will be really beneficial. They'll give us 5, 10 percent of theirs for the emergency power.

And the other thing that we value is these two-ways and ERT meter will improve custom service. And the last is energy efficiency. I think the last time we got this grant money, and get all the information to help us to implement a lot of efficiency programs. And we think we're going to continue on that line.

Okay, here's the thing we think we can talk about. Right now we like to see using a public wireless network to get to the homes. You know, if every utility putting all their own network, and limited space, we can share these bandwidths, all these technology.

If we can have every utility in California, we have a standard, say use the public wireless network. And I heard this morning Edison's already going to the WAN system, they use the other form. But I don't know why we stop at there. Why don't we push all the way to the home.

Now, go back to the same question in the past, you know. Incremental meter costs are not

that much if we can handle it. The trouble is the network, the IT part. We're not, you know, not good at IT. But that going to cure us.

And also a lot of investment in the IT. And if you look at public network, (inaudible) building for the last two years, we can match that. And they have the whole -- of working on the technology for the solutions. And you talk about home security, you talk about solid state, talk about smart cost and original cost, all these technology has to be, you know, have a platform for everybody to work on.

And if L.A. were to go into a two-way system, if the meter smart enough, can aggregate all the telecom service, you talk about home network systems, you talk about home security systems, energy efficiency, net metering, basically internet.

If we all come together, go to the public network and say, you know what, you give us a flat fee and we go in with the meter reading using your system to do it. Because they're already invented, you know, already implemented a system. We don't have to duplicate that system. And we'd save the resource, public resource, and

just work on that meter.

And to put all the bells and whistles and the functions on that meter, I think that's a shortcut for us. We cut our probably in half because now you only plug the meter in, you walk away. The communication, all building with a meter. And that way you have less headaches. I think that will work.

And you look at our cellphone. You open up second line is cheaper. I think it's about $9 or something that, you know, you can get. So, I think on the same line we go back to the public wireless company and say, hey, you know what, give us a deal, read the meters, do the network and use Zigbee technology where you can even search the internet. All these, but through the meter go back to the network.

And my next slide tell you that how much money being put into the network. You look at the BPL and you look at the matched system, and the RF system which we talk about. And then you look at the public wireless system. They are at the $120 billion, the last column. And all other technology only hundreds of millions dollars, can match with that system.

So, if we have a network system then we will do it. It's easy. But if we have to put a network system, we have to do all this manage that, it's going to be difficult for us. And hopefully I will just ask, well, you know, help us to, you know, pave the way for us.

What we recommend is that over 30 kW we should do all with the wireless two-way communicating system. And that meter currently has the remote control, load control, you know, function on that. So, we can design some of the rates and have, you know, to interrupt the customers so you can shut off part of the usage during the peak time. And outage notification. You talk about (inaudible), all the functions already there for the high-end customers, which we can do it.

The low end, the two-way system, if they're over 1200 kWh, yes, we can also put in those two-way smart meters, and do a time-of-use, you know, all these other home load management system.

Okay, that's probably of all my presentation.

PRESIDING MEMBER PFANNENSTIEL: Thank

you. Your idea on the public wireless network, is that in place now in L.A.? Is it --

MR. CHEN: Yes.

PRESIDING MEMBER PFANNENSTIEL: -- intended to be? So the system is already in place?

MR. CHEN: Public network it's AT&T or Verizon; a system that's already shared by everybody.

PRESIDING MEMBER PFANNENSTIEL: So you don't need anything additionally in terms of the network?

MR. CHEN: No.

PRESIDING MEMBER PFANNENSTIEL: So then the question is are you -- so the meters you're getting are going to use the public wireless network as their platform, right?

MR. CHEN: Right.

PRESIDING MEMBER PFANNENSTIEL: But still even with that, --

MR. CHEN: Right.

PRESIDING MEMBER PFANNENSTIEL: -- you are only getting, you know, a relatively small handful of these AMI meters, the 75,000 residential is the number.

MR. CHEN: The price right now is not low enough that we will deploy a lot because the monthly service charge costs us, you know, somewhere around $5 to -- they promise us, you know, can lower that to a $1 range. Which, you know, we -- but it won't be continuously every day usage. You get a once-a-month usage.

For us to get a daily usage, or can even get on the internet, then we talk about $5 to $10 that range. But we like to see lower that so that we can deploy those meter on everybody.

ASSOCIATE MEMBER ROSENFELD: But I keep asking the same sort of question. In terms of total economics, --

MR. CHEN: Right.

ASSOCIATE MEMBER ROSENFELD: -- this morning -- well, for years we've known that the IOUs do business cases for doing complete AMI and time-dependent tariffs and communication systems. And the business case works.

And you're a big utility. I still haven't understood why it doesn't work for you.

MR. CHEN: Because the amount of usage, I mean probably all rates are, you know, different, IOUs. They have a peaking. Look at

their rates for above 30 cents.

Ours, you know, pretty flat to 15, you know, 18 cents, that's the extreme. And, you know, that's the difference. And also the usage, I don't know, maybe we have more coastal, you know, the average usage is kind of, you know, not have a lot of volume for us.

In the volume I heard that PG&E talk about, yeah, I thinking, you know, two-way is there, we can do it. But if you look at Santa Monica, you know, you have -- we don't have air conditioning in the home, and how can we, you know, justify that. That would be hard on the business case.

But we see it, you know, if we share all these other functions, you know, home securities, and you know, internet, all these other stuff that if you add on that, yeah, we can get there. But we have to have a standard that everybody going to share that so the cost going to go way down.

PRESIDING MEMBER PFANNENSTIEL: What if you shared meter reading savings with the gas company, for example?

MR. CHEN: Yes. We talk about --

PRESIDING MEMBER PFANNENSTIEL: Have you

looked at that, yet?

MR. CHEN: Yes, we talk about it. They are also doing ERT with us, the IF meters, you know. They like ask to read about 100,000 for the gas companies. And, you know, still each meter reading is about 50 cents nationwide average.

So, you know, if you add all together it's about 50 Water and Power, and you know, gas. But if you add some other benefits on it, yes, will be there. But it takes, you know, how the network going to be funds, and that's the issue here.

PRESIDING MEMBER PFANNENSTIEL: Now you've done a business case to look at the different kind of technologies that would make sense --

MR. CHEN: Yes.

PRESIDING MEMBER PFANNENSTIEL: -- for LADWP in the future? Could I get a copy of that?

MR. CHEN: Okay.

PRESIDING MEMBER PFANNENSTIEL: Could we get one for the record, is what I really --

MR. CHEN: Okay. We tried, I mean I don't think we write it out on, you know, how different technology, but we tried TWAX system, we

tried the modem system, we tried the ERT system, we tried the two-way system, I think we end up picking two-way and ERT system. And we don't have writeup, but -- the last ten years we try different systems, and we end up with these two at this point.

But we have our business case.

PRESIDING MEMBER PFANNENSTIEL: It would be interesting for us to be able to see that.

MR. CHEN: Okay.

PRESIDING MEMBER PFANNENSTIEL: Thank you.

MR. CHEN: All right.

MR. HUNGERFORD: All right. And next we have Erik Krause from SMUD, Sacramento Municipal Utility District. And thanks for making the drive.

MR KRAUSE: Oh, thank you.

(Laughter.)

MR KRAUSE: It was actually a train ride; it was kind of nice.

Thanks for letting me come here. I wanted to give you an overview of where we are with SMUD. I'm looking more toward the future than where we are right now.

So I'm going to start off by talking with you about SMUD's vision. And this is what helped us drive where we're heading with advanced metering infrastructure in the future.

SMUD's vision is to empower our customers with solutions and options that increase energy efficiency, protect the environment, reduce global warming and lower the cost to serve our region.

Based on that vision what we did was try to develop the AMI project objective or objectives, as you might call them. And objective of our AMI project is to implement an AMI system for all 610,000 residential and commercial customers by the end of 2011 that will significantly reduce ongoing operational costs, enable SMUD to improve service to our customers, create a foundation on which SMUD can build a variety of programs such as demand response, load management, energy efficiency and time-based pricing programs, and enable SMUD and our customers to reduce our impact on the environment. Some pretty big objectives there to have on my shoulders.

We did go over a business case and I

will send that to you. I think it's actually posted on our website. I don't know exactly where it is, but I can send that to you.

We've actually gone through it twice. I was involved in the second version of it that we completed in 2007. We worked with a consulting firm to rehash numbers based on the new price points, our new labor costs and our new cost structures as natural gas continues to rise.

And we determined that we would have a positive business case at SMUD to go forward from the advanced metering infrastructure, which for a project manager who is just starting to launch our AMR project, and just starting to kick off a bunch of ERTs being deployed, it was quite a hit to be telling me at that moment, soon after we signed the contract for the ERT meters, okay, we need a new business case, okay we need to stop with the ERTs and move forward with the two-way AMI. It's been a busy couple of years for me.

As far as our financial benefits go, and we have these articulated in our business case, as well, 52 percent is meter reading. That's a big chunk. Obviously California wages are pretty high, even for meter readers, especially when you

tie in overtime and so on and so forth.

So we expect that we can reduce, if not 100 percent, very close to 100 percent of our meter readers by deploying these meters.

Billing, we expect to have some cost savings. We do a lot of manual checking of bills. Anytime a meter reader can't get into the backyard, and we haven't yet installed an ERT meter, we do some estimations. We have some customer reads in remote areas, et cetera. So we believe by doing this we can eliminate the bulk of that manual billing, which accounts to about 7 percent of our cost savings over time.

Credit. That includes avoidance of power theft; it includes avoidance of inactive usage. So between customers, when one moves in and another one moves out, sometimes we have inactive usage and we don't know who to charge for it. And as a muni we typically don't get too aggressive at trying to figure out and point fingers at who owes us the money. We just write it off.

Theft, as I mentioned. We've had, if you haven't seen the Sacramento Bee we have a lot of grow houses down in the south area. That can

add a lot of money to your write-offs. Some of them are hundreds of thousands of dollars before we catch them. So we believe that no only will we be able to, with some of these remote disconnect switches or service switches, disconnect those customers ahead of time, but we'll be able to use the data we're getting on a daily basis to see trends; figure out where there might be theft. And then work with the city police and whoever, sometimes FBI, to figure out where those people are.

Distribution benefits. That's kind of two layers there. That's both operational, being able to better understand how our distribution system is working, figuring out where outages occur, and looking for nested outages, et cetera, and being able to respond to those more quickly. As well as capital reductions or deferral of capital investments.

If we can realize that our new zero energy homes or solar smart homes use less energy, then we can design our systems so that we have smaller transformers, smaller substations, et cetera, to better serve those customers.

Then on the metering side, w are going

to be replacing these over the next three to five years. And as we do that we're getting rid of all those old meters out there. And I forget who it was saying this, but, you know, we won't be doing meter repairs. Once we decide on the AMI we'll take the meter out and put a new one in.

And these meters are such that you're not going to do a whole lot of repairs. It's like a little computer. If they're broken you're going to go out there, and we should have some warranties in place that we can replace those at little or no cost to the District going forward.

PRESIDING MEMBER PFANNENSTIEL: Erik, I notice you didn't give yourself any benefit for demand response.

MR KRAUSE: We left that off because we wanted to -- well, first of all, we needed to give our Board the opportunity to figure out what we want to do with demand response.

We did estimate that and the value for demand response TOU rates, load management, was about the same as what we expected from operational savings. So it could be significantly more benefits going forward.

But at the time we developed this

business case we didn't know enough about where the Board was going and where we were heading, or where the state was heading to include that. But we do expect --

ASSOCIATE MEMBER ROSENFELD: Wait a minute, I want to expand on that.

MR KRAUSE: Um-hum.

ASSOCIATE MEMBER ROSENFELD: Let's talk total dollars to make it clear. You've told me with great accuracy that meter reading is 50 percent of something, but you didn't say what the total of this was in dollars.

MR KRAUSE: The percentage there are percentages of the annual benefit from the AMI system.

ASSOCIATE MEMBER ROSENFELD: And could you say what that is in dollars, do you know?

MR KRAUSE: I need to be careful right now because we have an RFP on the street, and there's vendors in the room. So, I could give you that information; I can send you the business case document, it's in there.

ASSOCIATE MEMBER ROSENFELD: That'd be great. Now, but I'll just call it X for the --

MR KRAUSE: Yes.

ASSOCIATE MEMBER ROSENFELD: You said you get anther savings comparable with the operational savings. Does that mean with the 50 percent which you call meter reading? Or does it mean that you double the whole profit?

MR KRAUSE: Well, it depends on what assumptions you made. If you assume that we go forward and legislation comes forward on mandating TOU rates across the board, it's a significant benefit. If it's an opt-in or an opt-out, it makes a difference, as well.

But the range is equal to potentially, depending on how forceful we get with requirements and so forth, the operational benefits.

ASSOCIATE MEMBER ROSENFELD: Of the whole pie?

MR KRAUSE: Correct.

ASSOCIATE MEMBER ROSENFELD: Thanks.

MR KRAUSE: And where natural gas prices go, as well. If they go up, keep going up, it can make a big difference.

As far as the AMI we expect to select, we haven't selected it. Actually our bids are on the street, as I mentioned, that's why I need to be very careful. June 17th is the due date. The

vendors will need to supply sample meters and their responses at that time.

We expect to analyze those proposals over the next few months. And we have a very aggressive schedule to be at contract by October 1st of this year.

From what we've seen with IOUs and others that are still in negotiations, that may be an unrealistic goal, but we're still keeping it there and hoping we can meet it. We realize that things could shift six months plus, depending on what happens during those negotiations.

As far as what we expect to include, we expect it to be a robust and scalable network that would be leverage for future smart grid applications. I know there's a lot of confusion about what smart grid is, and different people have different interpretations of it. But as far as being able to do demand limiting, load management system TOU rates, et cetera, we want it to be able to do that.

It will include two-way interval meters for all SMUD residential and commercial. It will include some sort of home area network capabilities. We haven't decided that we want

ZigBee. We haven't decided that we want Thru-the-meter. We're going to look at that as we go through the process.

It will include 200 amp service switches. We actually, in our RFP, we set up a couple different scenarios. Our business case was based on the assumption that we would put these at about 40,000 locations. Primarily residences that have had several disconnect for nonpayments over the last year or two. And that way we could get the bulk of the benefit from those.

We also are looking at potentially any multifamily or non-owner-occupied facilities, because we figure that way we can get the benefit when they move out.

And then we also asked on the RFP for 100 percent solution. So any 200 amp meter should have that on there.

Truthfully, I think depending on where we come in with pricing and talking with the Board, I'd say we're more likely to go toward 100 percent option than the partial deployment.

AMI master station software, this is just the software application that you use to manage the meters, gather the data back and

program and update meters as necessary.

And we do have, we're in the midst right now of selecting a meter data management solution. We're in negotiations now, so I can't tell you much more about that, either. But we do intend to integrate in the meter data management system, and through the meter data management system to integrate into our SAP, which is our accounting system, and our outage management system, which is -- I can't remember the name, but we have an outage management system already in place.

And then on top of that part of the project is that we're going to develop the CSR customer tools to access and view energy usage data.

So here's our preliminary timeline.

ASSOCIATE MEMBER ROSENFELD: I'm sorry, --

MR KRAUSE: Yeah.

ASSOCIATE MEMBER ROSENFELD: -- I'm -- what does CSR stand for?

MR KRAUSE: Oh, I'm sorry, customer service representative, people at our contact center that answer the phones. It could be a billing rep, as well.

ASSOCIATE MEMBER ROSENFELD: Oh, okay.

MR KRAUSE: Anybody that contacts a customer.

So here's our schedule. Like I said, I think the most aggressive piece is that AMI contract award that we start with. And it's our critical path item. If we don't get that contract by September, then at least until the end of the acceptance test we're pushing, we figure we can always squeeze the installation and do more and more of those installations a year.

I forget what SCE said they'd do in a day. I think we can do, 50 days we can do all of SMUD at their rate.

So, what we're looking to do is if we get the contract nailed down by the end of September, we'll spend about the next three months of this year, and maybe a month of next year developing, designing, building the requirements, figuring out how the integration hooks will work, et cetera.

And then the first two quarters of 2009 we will do the actual acceptance test. It will be about 5000 to 10,000 meters out there. More than likely the acceptance test would be partially

downtown core because depending on what type of technology you select, you might run into issues with wireless downtown, with the buildings and the cement and the below-ground systems. We'll also do some type of rural pilot, as well.

Assuming that goes well and we test everything and it works as expected, we intend to go down to full deployment round about May or June of 2009, and be done by 2011.

We haven't decided yet, we originally were going to focus purely on the commercial initially, and then move on to the residential. Right now the steering committee is looking at that as options. Part of our determination will be based on where our Board goes as far as time-of-use rates go, where we prioritize other items that we're planning on doing.

So that's all I have.

PRESIDING MEMBER PFANNENSTIEL: Your Board has committed to this program and this kind of schedule? I know it may give or take some, but this is where you're going?

MR KRAUSE: Yeah. We do have to go back to the Board once we have a recommendation on selection, on a vendor selection. And they may

come back, you know, depending on how the vendors come back, they may come back and tell us we're crazy, you're not going to meet this. And then we go back to the Board with that information, as well.

We do need to get budget approval from the Board. But they have seen the business case; they have authorized us to go forward with procurement. The key point is once we come t a point where we say we need X million dollars for this proposal, here's who we think we're going to go with, then they need to authorize that and sign off.

They still have the option to say, sorry, it's too much money. But I doubt that'll happen.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Most impressive.

MR. HUNGERFORD: Thank you, Erik. Now we have a presentation by the Division of Ratepayer Advocates of the Public Utilities Commission, and Rebecca Lee is going to do the presenting.

(Pause.)

MS. LEE: I'm Rebecca Lee and I work at

the Division of Ratepayer Advocates; that is an independently budgeted division housed within the CPUC. And we intervene, and we have been intervening in AMI proceedings at the CPUC.

And also one of the caveats I need to address today is that we are currently intervening in PG&E's upgrade AMI application. So anything I say today will pertain only to our experience with the original application and also the SDG&E and the Edison AMI deployment.

What we do, so DRA's participation in AMI deployment applications has been that we had a partial settlement with PG&E in its original AMI deployment. And we were fortunate to reach full settlement with Edison and SDG&E in their AMI applications. And we are also currently reviewing the cost effectiveness and reasonableness of PG&E's upgrade.

Our objective, my short presentation today is just really to just go over what DRA's objective is in our intervening in these AMI applications.

And our objective is very simple; it's that we see that an AMI system and demand response programs are enabled by AMI and must be cost

effective. And we prefer that they be cost effective from the ratepayer's perspective, obviously.

And that leads into having an AMI system that incorporates nonproprietary communication standards, and that is interoperable with future smart grid technology.

One thing that some of you would know, Ted Geilen of DRA has also been a strong proponent of having customer enabling technology as being part of an AMI system.

This is just a brief overview of the lessons learned from our most recent experience. And fortunately Mr. Paul DeMartini is here today. If I were to present our settlement agreement wrong, he's here to correct me.

And so this is the business case that we were able to come to agreement with. And these are just a few outlines of the things that DRA stuck up for and we were fortunate to agree with Edison on.

One thing, the first, is the benefit realization aspect. The O&M benefits of the AMI applications will actually accrue as a credit to a smart connect balancing account. So this is an

insurance for the ratepayer such that the O&M benefits will actually reduce the revenue requirement eventually will have to be collected for the cost of AMI.

And another point is the risk-sharing aspect. This is nothing new, but up to $100 million of cost overrun will be shared by ratepayers and the shareholders.

And we've also encouraged, and Edison was gracious enough, to commit to looking into exploring the potential of network sharing with water and gas utilities to reap benefits of shared network. And we've supported interoperable energy management technology. And we've heard the standards that be, being mentioned today many times. We supported that.

And one thing we also proposed. This was not part of the settlement, but I wanted to bring up today was that for the ratepayers cost should be allocated in such a way that is consistent with how benefits will flow to each customer class. And we feel that this is maybe obvious, maybe not. But this is important from the ratepayers' perspective.

And we've also proposed in Edison's AMI

application, as well as in a previous proceeding with SDG&E, that a AMI-enabled price base for demand response programs, such as the peak-time rebate program, should be designed in such a way that free ridership is minimized.

And one of the things that Tom Roberts I think presented today, and also it was previously mentioned, that for a program such as PTR, if we were to give customers a higher incentive to participate in a demand response program when they have enabling technology, then that is an elegant scheme. If customers have enabling technology, then they're more likely to respond, and hence they should receive a higher reward for responding. And that was another aspect that DRA promoted.

And this is really basic, this slide is very basic. And it just goes to say that obviously standardization can occur at different levels. It can occur for the communications between the meter and the home, between the meter and utility. And DRA has so far supported there be a standardized communication gateway between the meter into the home.

And a customer may opt with a different

communication standard, but we've supported that for communication of the meter to the home that it makes sense, from the ratepayers' perspective, to standardize in one communication protocol; that is ZigBee.

And that's the conclusion of my last slide. And that AMI implementation should be cost effective and lead to actual ratepayer benefits. So, that's good to have the last word.

(Laughter.)

PRESIDING MEMBER PFANNENSTIEL: Thank you. Any questions?

ASSOCIATE MEMBER ROSENFELD: Yeah. Since there's so much interest in communication protocols, standardized, sorry, I guess I'd like to ask the three IOUs here -- we don't have a panel, but we said we might get back to them.

PRESIDING MEMBER PFANNENSTIEL: Sure.

ASSOCIATE MEMBER ROSENFELD: If they would care to make comments. I presume that this is not a brand new idea. Would PG&E or Edison or San Diego care to talk about how much discussion there's been about statewide communications protocol?

Good afternoon.

MS. COREY: Jana Corey from PG&E. One of the things I wanted to comment on is that there is a consensus around what the inhome protocol should be, which is ZigBee. That's a very -- it's a prevalent, the industry's gathered around that. It may not be the most perfect, but it's improving because of OpenHand and some of the participation across the country in that space.

One of the technical complications I wanted to just mention is that if you have a -- that's a radio frequency based communication protocol, and if you have a multidwelling unit, like a large apartment structure, RF doesn't go from the meter to the higher parts of the facility.

So the way you get from the meter into the home may be a different technical solution than an RF radio. So I just wanted to make it clear that the industry's closing on a concept which says that as long as you can get into the home and you can bridge to an RF ZigBee solution, that qualifies as a common protocol in the home. So the inhome facility equipment manufacturers can communicate using ZigBee.

So, I just wanted to make that

clarification because we're actively looking at a powerline, actually a HomePlug solution which is on the wiring in the home that gets from the meter into the home, and then using an RF bridge.

MR. DeMARTINI: The only thing I'd add to what Jana said is similar to what I said earlier, which is that there are really two things.

We do see that there are potentially a powerline carrier based technology that would be used around the home, as Jana said. But one of the things that we're actively working with PG&E and San Diego on is the good work that has been done around something that's called the smart energy profiles in ZigBee.

That is to enable ZigBee to talk to thermostats and inhome displays and other smart appliances and the like, as well as the plug-in electric vehicle, is to take those profiles and have those adopted by the HomePlug command and control standard so that they can talk to each other. So you don't need a complex translation on language.

So that, for example, you have two devices that are able to speak French to each

other, not one speaking English and another speaking French. So the idea being that we can bridge across much more cost effectively.

Also looking at technologies that are emerging around -- and some of these already exist today -- very simple bridging technologies that you can plug into a wall that allow that to receive the ZigBee signal and convert that into HomePlug command and control. So that's something we're looking at.

I think the challenge has been that HomePlug's been lagging behind in terms of market developments. Probably a year and a half or so behind. And we're looking to marshal the efforts of the three utilities with others in the industry to try and move this along with HomePlug, much as we've done actually, very successfully, with ZigBee.

MR. REGULY: The only thing that I'd like to add to that is there is some applications where the wireless technology works better. And those are in those areas that are not directly connected to, let's say, like 120 volt outlet, like a thermostat, an inhome display that you want to walk around with. ZigBee works very well

there.

There's other areas where a wire like HomePlug does work. I think it was Jana mentioned the RF can only go so far. ZigBee is a mesh technology, so it can hop. But there is going to be some instances where it's not pervasive enough to get to all the end points. And that's why, like Paul was mentioning, we want interoperability between those two standards.

PRESIDING MEMBER PFANNENSTIEL: Great. I would now just sort of open the floor for anybody here who'd like to comment. And then we'll see if there are people on the phone who would also like to comment.

Please, just come up to a microphone, identify yourself, and --

MR. NAHIGIAN: Thank you. Hi. My name is Jeff Nahigian; I'm with JBS Energy; I'm a Senior Economist. We work as consultants to The Utility Reform Network, as well as Utility Consumer Action Network, UCAN.

We have been involved, and I've been personally involved in all of the AMI cases that have occurred before the PUC, which considering both predeployment and deployment cases, it

amounts to probably about seven or eight cases so far.

I wanted to just basically address a couple things that in terms -- that were being asked today in terms of cost effectiveness for the AMI projects. And I think there's, from listening over the web this morning and listening to what's going on today, there seems to be a perception that rates are going to go down because the business cases are so positive for the investor-owned utilities.

And I will say that that's not true. I very strongly believe that that's not true. Rates will go up, not down. And the reason for that is because the business case analysis are not cost effective on an operational basis, even as they've been adopted by the Commission.

And it's the operational benefits that flow back to the ratepayers as Rebecca was discussing that actually are tangible and actually work to reduce rates. And those are the things associated with the meter reading, the billing savings, the CSR, distribution savings if possible.

Added on top of that, with the business

case analysis, was a whole large amount of what were called demand response benefits that you've all recognized. And those may or may not flow back to the ratepayers, if or if not they occur.

And they are fairly speculative.

On top of that there are another additional amount of supposed benefits called social benefits or societal benefits. And the utilities have discussed that. Those are energy theft, meter accuracy.

And these are particularly benefits that will not reduce rates whatsoever because you're paying for those benefits right now. For instance, in terms of meter accuracy if you have better meter accuracy then you may -- well, let me back up.

What is happening right now in terms of meter accuracy and energy theft, all the costs associated with those are already recovered in rates right now. And it's actually a little multiplier on top of an energy sales forecast that allows you to jack the sales forecast up, because you may have some meter inaccuracies, you may have some energy theft.

The ratepayers are paying for that now.

And their rates won't go down if energy theft benefits and meter accuracy benefits actually do occur. It's --

ASSOCIATE MEMBER ROSENFELD: Well, actually, Jeff, it's a tiny point, but I would kind of think that some, if you charged for theft to the thief that his usage -- there is elasticity on thieves, I would think.

(Laughter.)

MR. NAHIGIAN: Yeah, it's a good point, sir. However, also there's also, if you could charge the theft to the guy, that would be possible. And if you could get past payments that you felt that they had stolen, I would agree. But that's not what the utilities are going to do. They don't --

ASSOCIATE MEMBER ROSENFELD: It's a small point, I --

MR. NAHIGIAN: And oftentimes they don't have money to pay. But, it's a small point, I agree, sir.

And there's also some controversy as to whether or not energy theft will increase or decrease because of AMI. Because you don't have meter readers out here, and most of the utilities

understand that the meter readers are the -- they're the eyes and ears of the utility. And so they're the ones that can actually physically look at a meter and see whether or not it's turned upside down or whatever. But it's a minor point.

And my major point here in trying to tell what's going on with the Commission is to tell you what the operational cost effectiveness is for the investor-owned AMI projects.

For instance, the San Diego Gas and Electric settled AMI project that's been settled and approved by the Commission, has somewhere between a 52 percent and 60 percent operational cost effectiveness. That means benefits are only 60 percent of total costs. Okay. So that doesn't, you know, rates are going to go up because of that.

And we've asked, one way of being able to provide other benefits back to ratepayers in terms of the demand response benefits is to get a guarantee from the utilities that they would guarantee that back to the ratepayers. We've asked for that in the PUC proceedings, and they've declined. Because they feel it's too speculative to be able to take a risk on that.

But what they have said is that we will provide those benefits, the actual tangible operational benefits we'll provide back in a sort of dollars-per-meter-installed basis, which is good.

And just to let you know, in terms of both TURN and UCAN, if the operational benefits were greater than the total costs, we would support these projects.

But our problem is that we found, and even under the utilities' own assumptions in all of their analysis, even under their assumptions, it's not close to cost effective.

Okay, so for San Diego, that's 52 to 60 percent of the total project costs on contained operational benefits. The recent settlement between the DRA and Edison has resulted, although Edison says that it is cost effective, with demand response benefits and operational benefits, that's almost a wash. It's about one, one with maybe, you know, 1.04, something like that. I mean correct me if I'm wrong, but I think I'm in the ballpark.

The additional benefits that make it up to like a 1.2 also involve the meter accuracy

benefits and the energy theft benefits that were discussed earlier before, that will have no effect on revenue requirements, and thus no benefit to ratepayers.

Third, for PG&E, PG&E when they first started their original AMI project had the highest operational cost effectiveness. And when that was adopted by the Commission that resulted in 89 percent operational cost effectiveness.

And those benefits also were supposed to be provided back -- the operational benefits provided back on a dollars-per-meter-deployed basis.

And because there's been a delay right now, if things had occurred as the Commission's decision 0607027 had thought, then we would be getting, right now PG&E ratepayers would be getting approximately right now about $1.5 million per month credited to the balancing account and benefits. But because that project's been delayed, and it's accounted as it was originally forecast by that time, we would probably have close to about $10 million in benefits.

Because the project's been delayed we have about $500,000 in benefits provided back to

ratepayers. Okay, so that's something that has not occurred.

And now, with the PG&E AMI upgrade, because of the cost and the additional benefits added onto the original AMI project, that now goes from an 89 percent cost effectiveness on an operational benefit somewhere down to, I believe, 61 percent.

So although the technology is better; it's a solid state meter, everybody's all excited, we've got remote disconnects integrated into the circuit, from the ratepayers' perspective it's a step backwards. And it shows that the operational benefits are less than if PG&E went forth with their original application. There are also other issues associated with that.

But that's basically what -- that's the major point I'd want to make, that rates are not going to go down because of AMI for the investor-owned utilities.

And until the operational benefits and the business case analysis is only adopted and authorized where operational benefits are greater than operational costs, rates will go up. And that has not occurred. And it's not even close to

it yet.

So that's my speech.

ASSOCIATE MEMBER ROSENFELD: Let's see, I'm a little puzzled, though. First of all, I don't think any of us expects that on an absolute basis to see rates go down anyway because natural gas is expensive and power plants are expensive and labor is getting more expensive and so on.

MR. NAHIGIAN: Well, --

ASSOCIATE MEMBER ROSENFELD: So what I guess you're saying is that all things considered you don't think that rates will go down compared with what? With stopping right now?

MR. NAHIGIAN: Okay. If all things were equal, we have no additional costs, we have AMI investment as it is, all other things being equal rates would go up because of the AMI investment because it would not provide sufficient operational benefits to pay for itself.

And we've done the analysis that shows, even under their original applications, the payback, the positive payback occurs in year '26 or year '27 under various assumptions. Longer than the useful life of the meter, itself.

ASSOCIATE MEMBER ROSENFELD: Okay, but

then there are the intangibles that we don't know how to estimate very well. All this technology will allow customers to understand their electric use, their gas use, they will use better.

The costs that you -- the total costs that you are concerned about, a few percent of revenue requirement every year. And if we were to get a 10 percent reduction in electric use, because of better understanding, I think in my mind that would swamp the uncertainty.

MR. NAHIGIAN: If you got 10 percent, yeah. But I have to say that's probably an over-estimation. And if the utilities were --

ASSOCIATE MEMBER ROSENFELD: You only need a few percent to break even.

MR. NAHIGIAN: I can't really address it, with all due respect I think it's a little vague for me to actually --

ASSOCIATE MEMBER ROSENFELD: Which is okay.

MR. NAHIGIAN: -- put my teeth around and be able to chew on.

PRESIDING MEMBER PFANNENSTIEL: Well, of course, we'd have a better chance of getting some of the demand response if we were able to offer

time-of-use rates, or time-varying rates --

MR. NAHIGIAN: Well, again, --

PRESIDING MEMBER PFANNENSTIEL: -- into a rate design --

ASSOCIATE MEMBER ROSENFELD: That's what I'm assuming --

MR. NAHIGIAN: From our perspective -- right, but from our perspective, too, if you wanted to offer time-varying rates you don't need an AMI program to do that. You've had time-of-use rates around for 20, 25 years. And you don't need an AMI system --

PRESIDING MEMBER PFANNENSTIEL: -- on a limited number of residential, optional residential rate designs. Very limited.

MR. NAHIGIAN: I'm sorry, I didn't catch all that, Commissioner.

PRESIDING MEMBER PFANNENSTIEL: Very limited rates.

ASSOCIATE MEMBER ROSENFELD: Opt-in rates, voluntary rates. We can consider default opt-out.

MR. NAHIGIAN: PG&E's has residential time-of-use in maybe, I don't know, 200,000, 250,000 customers on that for the last 20 years.

ASSOCIATE MEMBER ROSENFELD: Well, Commissioner Pfannenstiel is saying that's a pitifully small fraction.

MR. NAHIGIAN: It's small, but, you know, I mean it depends on what you're doing. If you're going to ask them again -- I mean I'm not here to talk about rate design or mandatory opt-in or opt-out. I'm just talking about the benefits and the operational benefits of the AMI system.

And I think you have a long ways to go in terms of demand response to be able to overcome that gap.

PRESIDING MEMBER PFANNENSTIEL: Thank you.

MR. NAHIGIAN: Thank you.

MR. GUNTHER: Erich Gunther with EnerNex Corporation and Chairman of the OpenHand working group.

Just wanted to emphasize something that Paul alluded to earlier regarding the information to be exchanged. One of the things that we're recommending in a variety of venues that I'm active in is that the regulatory community tried to avoid specifying specific technologies, but foster the development of well-understood

information models and transaction models such as the ZigBee smart energy profile that can be mapped to any underlying technology.

That is likely to remain much more stable over time because it's directly related to the applications, the overall problem we're trying to solve, as opposed to the underlying technology necessary to implement it, which like any other technology, will change more quickly.

We've already heard that ZigBee is a very good technology from its physical layer portion, the part that actually delivers bits and bytes from one point to the other.

The real value in what ZigBee has done is really in that smart energy profile, defining what's to be exchanged. And, oh, by the way, they've had to define how, as well, in order to make the whole package.

The willingness of ZigBee and others to translate that profile to HomePlug is a very welcome sign. And I'm also involved in the IEEE IntelligentGrid Coordinating Committee and we're getting ready to host a meeting trying to bring together the smart energy profile group, HomePlug people, folks from ASHRAE, BACNET, several other

organizations to try and harmonize those information models so that we've got one that makes it easy to implement those gateways that Paul alluded to. So they are a simple matter of translating at one layer, and not even have to translate in a -- fashion.

So, in summary, just would like to encourage that we write regulations and the like that encourages the interoperability, but don't specify how because that likely will be obsolete by the time the regulation is actually put together.

Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Others in the room? We have one person, I think, on the phone who'd like to address us. Richard Halverson.

MR. HALVERSON: My whole professional career with key personnel (inaudible) -- anyway, I got interested in electrical back in the year 2000. So I did a -- went back and picked up all the data on the (inaudible) 2000 to 2005.

And during that period of time I kept track of it. And you can all get on my -- I put together a presentation on the internet; and the

internet is www.emss -- for energy management systems solutions .org -- 1.org. 1.org.

And over that period of time in the last two years, 2004/2005, we get an average of 2,139,000 average -- 703,000, 187,000 -- per year. It also shows on that website the demand. When the heat went up we show it with sensors -- represent sensors in thermostats.

And so we put together a demand; it was all on the website. It shows when we had the heat storm back in 2006, I think it was 2006, but we had some material before that, I think, September 2005 we had a great increase in temperature. And also we plotted that, and we did that to Edison's, at the time I think we used -- and then they went to Itron. And so the demand was done with Itron software.

And so there is -- our presentation is all history, what happened and what we did. And I think you guys are doing a real good job, and I hope that we can continue to go forward with this. I think AMI is a solution, but there are other solutions such as thermostats, two-way thermostats. And we show you how -- there's a page on there for two-way communication

thermostat.

So that's my presentation. You can take a look at the website and make your own decision of what you think is the best way to go forward.

Thus, we think thermostats are one of the keys for two-way communication. Thank you very much.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Mr. Halverson.

Other comments?

ASSOCIATE MEMBER ROSENFELD: Yeah, I have a question for LADWP, again, on statewide communications.

Hi, Mr. Chen. I'm somewhat puzzled. I don't know whether I heard your plea correctly, but were you arguing for more than what's been discussed here about communications? You were arguing for statewide radio frequency communication system, right?

MR. CHEN: Either that -- yeah, we'd like to have a common communication system --

ASSOCIATE MEMBER ROSENFELD: A little closer to the mike.

MR. CHEN: Okay. We'd like to have a common communication network so that when the AMI

(inaudible) you know, IT capable. But if we just put in the meter and walk away and have the systems just register on the server, that would be the easiest way for us to implement.

And what I hear from IOUs they building a lot of network to pull the data back. They talk about the home network, the LAN and the WAN. You have several layers of communication going out.

Then, you know, for municipal utilities, it's pretty hard to pull that off. We don't have these kind of IT expertise in the company to do this stuff.

And also the question here is that do we want to go through all these installation and doing that network to get that information back since we already have the network. Billions of dollars already spent on the ratepayers, the phone bills. We have high phone bills already.

So if we have a system already in place why don't we just all go in there on the same system and negotiate a better price for AMI on the offpeak time, at night. We read our meters midnight, 1:00 in the morning. And we get our data back. And that way, you know, we all benefit. So -- more public, you know,

infrastructure. That will help us to do the business that way.

ASSOCIATE MEMBER ROSENFELD: Okay. There are two thoughts that come to mind. For the programmable communicating thermostats that we were going to require in Title 24, --

MR. CHEN: Right.

ASSOCIATE MEMBER ROSENFELD: -- we did have a one-way poor man's, if you wish, radio FM sideband proposal so that all the PCTs would be able to receive a price signal. And that turns out to be cheap and the big IOUs aren't particularly interested, but they also don't object to it.

But you're asking for more than that. You're asking for a two-way --

MR. CHEN: Right.

ASSOCIATE MEMBER ROSENFELD: -- system, which economics I've not thought about at all. I mean, each of the big IOUs has its system. Ted Reguly looks like he wants to make a comment. I'm just like trying to get you guys talking together a little bit, so, thank you, Ted.

MR. REGULY: Yeah. I think we looked at using public networks to communicate to the meter.

One of the big -- two difficulties. One is getting to the water and the gas meter, the public networks require a lot of power. You can't put a battery in there to do that.

The other one is we need to get to all our meters throughout our service territory all the time. And to build out a public network to do that, it's not designed to do that. You can cellphone coverage, you don't get it everywhere. That is one of the big problems.

Actually I think the City of Anaheim was looking at they rolled out a public wifi system, and ran into problems reading their meters using that.

ASSOCIATE MEMBER ROSENFELD: Well, wait, Ted, one second. Sorry.

MR. REGULY: That's all right.

ASSOCIATE MEMBER ROSENFELD: From my point of view, or from LADWP's point of view, if a public service -- if a public network got 80 percent of the customers, whatever, they would be able to get 80 percent of the demand response. And, you know, maybe hard-to-reach customers would remain hard to reach and would have to stay on pricing, time-independent tariffs, but that

doesn't seem like a complete death knell.

MR. REGULY: Yeah, you know, 50 percent, 60 percent of our business case relies on operational savings. And if you don't get that additional 20 percent, your costs go up, they don't go down.

MR. CHEN: I think we can just, you know, also use the public network like you said, just reach 80 percent. And the rest, if you really want to reach them, you still can build a network. Nobody can stop you, you know, just you patch it up, you know, to get the full network.

And also with the ZigBee technology you can get it to the water and the gas meter easy. I don't think you need a special, the full, you know, communication capability on each meter. All they have to do is just talk back to the electric meters. Then the electric meter can send the information back.

ASSOCIATE MEMBER ROSENFELD: Right. I was going to ask Ted, your communication between the extra meters is really just a piggyback system which goes 50 yards anyway, isn't it?

MR. REGULY: Yes. I do agree that to get, as long as you can get to the electric

meter --

ASSOCIATE MEMBER ROSENFELD: Yeah, okay.

MR. REGULY: -- then getting to the gas and electric, it will work fine. But, I have difficulty just getting to the electric meter with a public system.

ASSOCIATE MEMBER ROSENFELD: Okay. Maybe you'll have to settle for the RDS backup --

(Laughter.)

PRESIDING MEMBER PFANNENSTIEL: Mr. Halverson is back with one more comment.

MR. HALVERSON: All the savings that we have, why are they in -- in getting involved in the -- I got comments all over the United States, the same comments, we're not interested, we just pass it on to the -- anyway. Okay, that was one comment.

They have such a high -- budget that they don't have money to invest in conservation for the utilities. And they made several comments that this has been approached, they've been approached with savings before, it doesn't work.

So I think that there needs to be education, put together, because their public speakers go out and talk to these people and

actually show them that they can conserve energy and they can pay -- money and demand grid and also on the energy savings, themselves.

I think it's an educational program, and I think there's going to have to be more of that done by the utilities and by maybe third parties. There's going to have to be more monitoring done so that they can show them how that they can participate and help. Because our gas bills, alone for automobiles is going up, and we're going to face new problems -- how are we going to get the -- off the meters. Going to be submetering. How are we going to do that.

So there's a lot of things to be addressed in the future here. And I think that we need to all come together to understand this is a brand new territory that we're going to be getting into.

So, these are the issues that I've been encountered when I've been trying to help people. So maybe this will help out. And I think it was brought up from the last meeting that we had, why have we not made better progress from 2000 to now in getting people interested. I think it's education.

PRESIDING MEMBER PFANNENSTIEL: Yes, thank you.

MR. HALVERSON: So that's my last comment.

MR. HUNGERFORD: Mr. Halverson.

MR. HALVERSON: Yes.

MR. HUNGERFORD: This is David Hungerford. I would appreciate it if you would summarize your comments and submit them as written comments. In addition to the ones you submitted earlier. Just to make sure that we get all of your points into the record.

MR. HALVERSON: Okay, so who do I send it to?

MR. HUNGERFORD: If you look on the -- did you see the notice that was posted on our website on the load management page? You have my email address. Please email me and I'll give you the correct address and the directions on how to submit a comment into this docket.

MR. HALVERSON: Okay. Do you have my --

MR. HUNGERFORD: I do have your email address, as well. I will email you to make sure that you have mine.

MR. HALVERSON: Okay, thank you.

MR. HUNGERFORD: You're welcome.

PRESIDING MEMBER PFANNENSTIEL: No further comments in the room? Yes, please.

MR. MEACHAM: My name's Jim Meacham, I'm with CTG Energetics in Irvine Road.

ASSOCIATE MEMBER ROSENFELD: Say your name again.

MR. MEACHAM: Jim Meacham with CTG Energetics, an engineering consulting firm to the built environment.

And I have kind of an obvious comment, but it leads into a question. And that is that it strikes me that a lot of the conversation today has been somewhat hinged on what the actual realization of the energy savings might be in terms of the overall cost/benefit analysis for these systems.

And that some very conservative estimates from me on the order of 1 percent. But that might be as high as 5 percent. And that range of percentage has, as you pointed out, Commissioner Rosenfeld, a huge impact on the actual total costs of ownership savings to the end user.

But it's predicated on an understanding

of what types of systems actually are going to achieve that impact. And by that I mean there could be, and likely is, a very significant difference between day-behind informational feedback versus real time; whether that's only internet based, or whether there's a fixed device in the home and what the form factor and feedback mechanism of that device is.

So, the number of variables that we're talking about here are fairly large. And then that multiplies in terms of the actual savings that we can receive from the system.

So the question is what are we doing researchwise to understand the form factor implications, the day-behind versus real-time feedback while we're trying to build this business case of getting to those energy savings. And what are the -- you know, having targeted programs at understanding what the best rollout is, and understanding that making sure that these systems are poised to capture the optimum deployment of inhome feedback mechanisms.

ASSOCIATE MEMBER ROSENFELD: Yeah, I personally, not surprisingly, agree with what you said. And it seems as if we need more pilots. We

had this big statewide pilot program in which, even without any hardware and negligible feedback, we got a third to a half a kilowatt of response on critical peak days.

But we didn't look at all at what happens if everybody is on, if all the members of the pilot have hardware and are on critical peak pricing.

And I think put a little more operationally I would repeat your words and say, as systems go, we need pilot programs to see how the response -- how much demand response there is and how much total energy savings there is. I agree.

PRESIDING MEMBER PFANNENSTIEL: I'd like to say it a slightly different way, --

ASSOCIATE MEMBER ROSENFELD: All right.

PRESIDING MEMBER PFANNENSTIEL: -- in that I think, as the systems go in, we do need to measure, we need to find out what is happening. We need some way of making sure that we are, in fact, capturing the savings and adjust when we don't.

We will be having a followup workshop, one on rates and rate design issues, which I think

is really incredibly important. And another on enabling technologies. Again, both of those will contribute to getting the best use out of these, the metering part of the system, itself.

I think that there's a lot we don't know, and there's some fine line between what we, as regulators, can require and what we can enable and allow. Because we fortunately are not the Public Utilities Commission, we don't have to make that decision about the financial commitment.

But we do, and have, been very active in promoting what can be done in this area, what can be done both in terms of the operational savings and in terms of the demand response attributes. So we're going to continue to push that.

Your absolutely right that there's a lot more information. I think some of that information is not really going to be known until we actually get out there and get the stuff in the field, and then monitor it carefully.

Further thoughts, comments, points of view? Yeah, go ahead, Paul.

MR. DeMARTINI: I might just follow up on this point on the information. Actually there's a good basis to start to look at this --

ASSOCIATE MEMBER ROSENFELD: Paul, a little closer to the mike, as usual.

MR. DeMARTINI: Thank you. There's actually some good basis to take a look at this. The study I referenced earlier that Ted Geilen summarized, some of the research actually did break down the difference between day-ahead information and the effect on conservation, and real-time information, this ten-second interval information, and the effect on conservation.

Those were the bases that we used in our analysis to estimate the conservation effect. And then you can look at adoption rates in terms of technologies to be able to get this. And obviously look at ramp rates on meters to sort of look at it.

A couple things we're doing as part of this, because it is in our business case and we are moving forward, to your point, Commissioner Pfannenstiel, we are looking to do some trials, focus groups starting perhaps this year, certainly next year, to start looking at these various technologies.

Also we committed to this enabling the home PC with the display, and working with a

number of product manufacturers to help see how we get this out into the marketplace to start pushing forward on this pretty aggressively.

So I think we're going to get some things together. What we did is we've recently engaged IDEO, which is a product service and design company out of Silicon Valley. Pretty well known in the design space.

They do a lot of anthropological analysis, not just traditional focus group. And we're working with them to better understand customer interaction with information on how that might be able to take advantage of it.

So, we're expecting over the next year to really get some pretty good insights on how this might unfold, and how folks might take great advantage of the conservation.

I think to your earlier point, Commissioner Rosenfeld, we do see likewise that even though in the deployment period there only may be a 1.5 percent uplift, if you will, upward pressure on rates as a result of the capital that's being invested during the deployment period, that pays for itself. Starts turning positive two years after the case.

And certainly it doesn't even take into account what the impact on a customer's bill if they actually take advantage of the information, demand response, they could easily get the kind of numbers that you're talking about and things. That we've seen anywhere from 5 to 20 percent depending on how people respond. So we think it's very positive --

ASSOCIATE MEMBER ROSENFELD: Well, in fact, let me ask all three IOUs who've thought about this carefully and have business cases and know revenue requirement per year, I guess you annualize your costs over five years or something, some number like that.

MR. DeMARTINI: We looked at the analysis to say, you know, what -- certainly the heavy capital investment on the front end, and then obviously the benefits are very back end loaded on a 20-year business case period.

But that cross-over point is approximately in 2014, including the demand response benefits and energy conservation benefits that --

ASSOCIATE MEMBER ROSENFELD: Okay, so I'll word my statement differently because I don't

know how to annualize your front-loaded costs. But if Jana, who's going to submit us some written comments anyway, and you and San Diego, would -- did I say something wrong?

(Noes.)

ASSOCIATE MEMBER ROSENFELD: You agree?

MR. DeMARTINI: Yes.

ASSOCIATE MEMBER ROSENFELD: Oh. Would submit a statement which said in order to pay for the whole AMI business, which numbers you know, would be offset by n percent per year conservation. I'm thinking it's like 3 percent, but I don't know the number. And I think we'd like to know that number.

MR. DeMARTINI: Oh, on average, that's what I was trying to explain, in our case it's about a 1.5 percent on average increase, you know, potential uplift in rates, right, from the capital that's being invested.

So if a customer saved -- to your earlier point all they have to do is save 2 percent and they've paid for it on average. Actually there's a little difference by customer class, but that's --

ASSOCIATE MEMBER ROSENFELD: Sure.

PRESIDING MEMBER PFANNENSTIEL: Great.

ASSOCIATE MEMBER ROSENFELD: And if the other two utilities could put that number in, too, I, at least, would be very happy.

PRESIDING MEMBER PFANNENSTIEL: This has been a really useful workshop for me. I finally am feeling like I'm understanding the functionality across the different metering decisions that have been made, and a much better understanding than I did about where we're going in this state on advanced metering.

I think that the area that is still a little murky to me is where the publicly owned utilities, how they're thinking about this, and why their conclusions are so much different, in some cases, than the investor-owned, and in fact, in other cases are just -- they're finding just what the investor-owned utilities are finding.

I think that's going to require a little more probing on our part. But I really appreciate everybody coming in and being open and discussing with us what your plans are and what you see this as opportunities are, going forward.

Commissioner Rosenfeld, any final comments?

ASSOCIATE MEMBER ROSENFELD: No, I learned a lot, also. Thank you very much.

Mr. Hungerford, anything else?

MR. HUNGERFORD: Just a couple of reminders. The written comments are due by June 3rd into the docket. The instructions are in the notice that you all received, and is available on our website.

And our next workshop will be on June 10th on rate design, incentives and market integration. We look forward to seeing you there. And for those of you who will be participating, I'll be communicating with you within the next few days.

Thanks very much for coming.

PRESIDING MEMBER PFANNENSTIEL: Thank you, all. We'll be adjourned.

(Whereupon, at 3:02 p.m., the workshop was adjourned.)

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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 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 6th day of June, 2008.