COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of: )<br>
)<br>
Summer 2008 Electricity Supply ) Docket No.<br>
and Demand Outlook ) 08-SDO-1<br>
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CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

WEDNESDAY, JANUARY 16, 2008

1:00 P.M.

ORIGINAL

Reported by:
Ramona Cota
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COMMISSIONERS PRESENT

Jeffrey D. Byron, Presiding Member

John Geesman, Associate Member

Jackalyne Pfannenstiel, Chairperson

STAFF and ADVISORS PRESENT

Laurie ten Hope, Advisor

Suzanne Korosec, Advisor

Denny Brown

Lynn Marshall

David Hungerford

Jim Woodward

Steve Fosnaugh

ALSO PRESENT

Robin Smutny-Jones
California Independent System Operator

Manuel Alvarez
David Reed
Southern California Edison Company

Gary Lawson
Sacramento Municipal Utility District

Osman Sezgen
William Tom
Curtis A. Hatton
Pacific Gas and Electric Company

Tim Vonder (via teleconference)
Athena Vesa (via teleconference)
San Diego Gas and Electric Company

Robert E. Burt
Insulation Contractors Association

# I N D E X

I N D E X

P R O C E E D I N G S

1:00 p.m.

PRESIDING MEMBER BYRON: Good afternoon. Welcome to the Electricity Committee workshop on the summer 2008 supply and demand outlook.

I'm Jeff Byron, Presiding Member of the Electricity Committee. With me here at the dais is my Associate Member on that Committee, Commissioner Geesman. And joining us is the Chair of our Commission, Chairman Pfannenstiel. My Advisor, Laurie ten Hope, all the way to my right. And Commissioner Geesman's Advisor, Suzanne Korosec.

I don't know what else to say, Denny, except I think we'll turn it over to Mr. Brown and we'll proceed with our workshop. You know what, I do want to add one more thing.

This is a little bit earlier, I think, than in most years when we deal with the summer outlook. And I think it's fair to say it's in response to the Assembly Committee Utility and Commerce's interest in this subject a little earlier than normal, as well. We're trying to be responsive.

And I'd like to thank the staff very

much for being able to pull this workshop together in very short order. And also for all those that are here to participate. We really did try to be responsive to our Legislature, and I thank you very much for being here today.

Mr. Brown.

MR. BROWN: Thank you, Commissioner Byron. Good afternoon, Commissioners, Advisors, Staff and guests. I'm Denny Brown with the electricity analysis office.

First I'd like to welcome everybody to this afternoon's workshop. And I'd also like to thank you for participating and to help us better understand California's complex electricity system.

Just a few housekeeping items before we begin. For those that are not familiar with the building the closest restrooms are right across the hall. There's a snack bar on the second floor under the white awning.

Lastly, in the event of an emergency and the building is evacuated, please follow our employees to the appropriate exits. We will reconvene at Roosevelt Park located diagonally across the street from this building. Please proceed calmly and quickly, again following the employees with whom you are meeting, to safely exit the building. Thank you.

The topics for today's workshop will include the summer 2008 supply and demand outlook. We'll have an overview of our peak demand forecast, a discussion of demand response and interruptible load programs and how they're utilized by the utilities. As well as the potential impacts of dry hydro conditions -- or various hydro conditions on capacity.

The purpose of today's workshop is to get stakeholder comments prior to presenting results to the Governor and Legislature; request input on impact of dry hydro conditions on capacity; and to hear comments on how demand response and interruptible load programs are utilized at the utility level.

We will start with the summer 2008 electricity supply and demand outlook. Just to provide a quick overview, I'll discuss the changes since the 2007 report that came out in June. We'll discuss various planning reserve margins for the four regions that we evaluate; provide a cumulative probability distribution for our probablistic assessment of the three regions that we include in that. And then finish up with some detailed assumption data, resource assumptions.

Since the 2007 outlook we really have not had any major changes to the methodology. In fact, very few changes to the methodology. The majority of the work we've done for 2008 is to update the values to reflect 2008 data, as well as to relocate some generation and some assumptions.

We moved Calpine Sutter from the SMUD control area to the California ISO control area as we found that it does have a participating agreement with the California ISO.

We've also reduced Western's Central Valley Project imports by about 250 megawatts to reflect their capacity that's used to meet their internal load.

We do provide the outlook in both the deterministic and probablistic format. The deterministic format presenting the planning reserve margins for the four regions, California statewide, California ISO, north of Path 26, so the portion of the California ISO in northern California, as well as south of Path 26 for southern California.

And we further do probablistic analysis for the California ISO, NP-26 and SP-26. And we don't do a probablistic assessment for the statewide as it's made up of several control areas and they do not operate as a single system.

Okay, this table provides the 2008 summer outlook, electricity supply and demand outlook. They were broken into four columns providing the NP-26, northern California ISO, SP-26, southern California, the Cal-ISO as a whole, and the statewide.

And just in general, all the regions have improved slightly since 2007 with the exception of northern California where we've seen the planning reserve margin drop slightly.

Even with the drop in northern California it does still exceed the 15 to 17 percent planning reserve margin required by resource --

It's also important to note that we use a 3000 megawatt assumption for path 26 to -- that 3000 megawatts of energy is traveling from northern California to southern California. In reality, that could be north to south, the flow could be south to north, and I will explain this a little bit -- I have a slide to explain this a little bit further later on. But for these planning reserve margins we do use 3000 megawatts always flowing north to south.

As southern California resource margins continue to improve, that is an assumption we'll have to look at to balance that. In the operation of the system the California ISO, on a real-time basis, will move that energy to whichever region needs it to best operate the entire system.

And then also at the bottom of this chart the probability of involuntary firm load curtailments is provided. This is the probability of the state's emergency from the ISO. Again, even though NP-26 has a lower planning reserve margin than SP-26, it also has a lower probability of a stage 3. And this is due to the -- southern California has a -- the temperature has a greater impact on load in southern California. So a high temperature condition will result in a much greater increase per megawatt hour.

And then there's also much larger resource outage conditions that we can experience in California. For example, the DC line could drop, and that's the single largest contingency in

the State of California. So that has a much
greater impact on SP-26.

PRESIDING MEMBER BYRON: Mr. Brown, can I -- I'm going to slow you down a little bit, ask you if you'd go back to the previous slide. And if I could, just ask a couple of questions.

First of all, maybe you said this and I missed it, but why is Sutter now moved out of, I believe it was SMUD's control area into the ISO control area?

MR. BROWN: Okay, originally when SMUD formed its own control area and Calpine Sutter came online, they scheduled through SMUD control area. I'm not exactly sure what the timeframe is that they changed over to have a participating agreement with the ISO, but they now schedule through the ISO.

PRESIDING MEMBER BYRON: Okay.

MR. BROWN: So, if they would be in SMUD -- if they were still in SMUD we would consider that an import into the ISO. It would still be in the California statewide total, but because they're in -- California ISO is no longer an -- it's not an import, it's an existing generation resource.

PRESIDING MEMBER BYRON: Okay. And in this table, then, should it have shown up, or why doesn't it show up in the NP-26 category? In other words, I'm assuming it's a -- well, let me put the question that way. Where is the Sutter plant in this table?

MR. BROWN: It's now located in two columns in this table, the NP-26, as well as the California ISO. So it's moved into the existing generation because it's not a new addition. It is existing generation. So it was just an adjustment made to the existing generation number since 2007 outlook.

PRESIDING MEMBER BYRON: Okay, and I was thinking it might have shown up in the third line, high probability CA additions. Okay.

And where do you get your net interchange information for this table?

MR. BROWN: Must of the net interchange, this is what we feel the physical capability of the net interchange is does not have any contractual obligation to it.

The only adjustment we look at is if we really felt the northwest did not have enough surplus capacity to fill the 6000 megawatts that we assume from the northwest, or if the southwest didn't have enough capacity to fill these lines, then we would adjust these down.

We have reviewed quite a bit of data from the ISO, particularly July 24, 2006, to look at what imports they saw on that very high load day. And we feel like these are reasonable assumptions.

This is one area that our forecast has differed slightly with the California ISO; and some of that may be the way we treat the Central Valley Project. We treat the project as all being in SMUD's control area, as they schedule through SMUD.

The reality is they break up and they provide energy and capacity to several utilities, many within the ISO, and some may be scheduling through the ISO -- some of those facilities may be scheduling through the ISO.

So the bottomline we come out about the same. We may count it in import, they may count it as an existing generation number.

PRESIDING MEMBER BYRON: All right, thank you. I won't ask any more questions, but I do want to note that I'm probably going to lose my fellow two Commissioners here to other obligations here. And if you have any questions I'd like you to please feel free to interrupt at any time. I'll stop. Thanks, Mr. Brown, go ahead.

MR. BROWN: Okay, the purpose of this slide is to show the many inputs that we have when we do supply adequacy. The inputs that are in grey are the ones that we've done probablistic assessments of and randomize these values.

So after we randomize these values that are in grey, we will look at the demand scenario and compare it supply scenario to come up with a operating reserve margin. And every time we do this, for every input that we do this, that's one case.

We then run 5000 of these different supply-versus-demand scenarios to develop cumulative probability distribution.

And those 5000 draws provide the inputs to this graph here. If you look at the blue line running the entire length of the graph, this represents each of those 5000 cases.

The area in the upper left-hand is going to represent a day of low demand and low outage conditions. And as we move through the middle of the graph, demand is increasing or outages are increasing. And then finally, as we move down to the bottom portion of the graph, this is where the system is straining on both supply -- on the supply side as well as the demand side, with high forced outages, possibly a transmission line being out, as well as a possibly a one-in-ten temperature condition.

So once we get to the 7 percent -- once it looks like reserves are getting down below the 7 percent operating level we then add in demand response programs. And that's represented in the brown line underneath the blue. And they only go out to 7 percent because that's when they would be normally triggered. And we'll have some discussion on whether this is -- how the actual system operates. There's some various stages when some of these can be triggered.

And then finally when we get down to the 5 percent level, we have access to the interruptible load programs. This is a stage 2 condition. And the green line represents the operating reserve margins when we include all resources, demand response and interruptibles, and compared them against the various load conditions.

And this chart here represents the ISO, as a whole. The next two charts will break the individual regions.

And for the California ISO we're again forecasting a .6 percent of a loss of load, loss of firm load.

Same information for the NP-26 region. And for the NP-26 region we're forecasting a .7 of a percent probability of firm load curtailments.

And finally, SP-26. And for SP-26 the probability of firm load is 1.6 percent. And as you can see there's quite a wide gap between the demand response and interruptible load programs. And that's roughly 1000 megawatts of interruptible load kicking in, and that's how much impact it has on system operating conditions.

Okay, and just to run through the various assumptions going into the deterministic table that then flows into the probablistic. This is the existing generation. This is as of August 1, 2007. This table basically takes our number that we had in the 2007 outlook, confirms what generation additions came online, and then it's added to the various line items in the appropriate category.

And, Commissioner Byron, this is where the Sutter Power Plant was moved in on the merchant thermal line for NP-26. And subtracted from the nonCalifornia ISO at the bottom.

2008 additions. Because we are quite a bit earlier in the process than we normally would be, we will still have to do some followup to track how far along these additions are. All the additions we are tracking right now, major additions, are in the SP-26 region for 935 megawatts, as well as IID's peaker project for 78 megawatts in the nonCalifornia ISO portion.

I think Edison will have some comments on the Inland Empire project, as well.

This breaks out the net interchange and what goes into the net interchange for each of the various regions. The statewide and SP-26 totals have not changed. California ISO and NP-26 totals did change to account for the 250 megawatt reduction in Central Valley imports into the ISO control area.

And just to go back to the footnote on the actual outlook, itself, and talk about that 3000 megawatts that flows on Path 26, this is summer of 2006 net interchange numbers for the hour ending 4:00 in the afternoon.

The red line represents the 3000 megawatts that we include in the outlook. Negative number means that it's flowing north to south. As you can see by the actual data it's very wide-ranging of what it could potentially be.

Again, this looks at the different conditions in different regions. On July 24th, the area highlighted here, was a extreme load day in northern California. It was hot in southern California, as well, but it was an extreme event for northern California. So we can see that the California ISO was able to balance the flow on Path 26 to help accommodate that extreme load condition.

This chart represents why we think that the California-Oregon Intertie, as well as the Pacific DC Intertie, will be able to be filled to capacity this summer. This information is from the BPA whitebook, their Pacific Northwest loads and resources study. And it represents their surplus capacity by various water conditions.

So the dark blue line at the top represents the top 10 percent or the wettest years. The light blue line is the middle 80. And the black line represents bottom 10. And the brown line on here represents 1937, and that is the number, that's their driest water year on record and that's the number they use for their planning criteria.

The red bar across the middle represents the nonfirm exports from the northwest to California that we include in the outlook. And we actually include 6000, but because this is a forecast of their surplus they count some firm exports. Then we have to subtract those off of the number.

And finally this is just a breakdown of the demand response and interruptible load programs that we are including in the 2008 outlook. We'll have a much greater discussion on these a little bit later, but this is how the line-by-line breakout was -- this is how we came to the line-by-line breakout to come up with cumulative total.

Is there any questions? Or comments?

CHAIRPERSON PFANNENSTIEL: Just David Hungerford is going to talk later about the demand response and interruptible programs. Is he going to use this page to kind of go through what we expect for the summer? Or something like this?

MR. HUNGERFORD: Something like this.

CHAIRPERSON PFANNENSTIEL: Okay, I'll wait until that -- thank you.

MR. BROWN: Okay. Thank you. Because there's an awful lot of acronyms on here that I'm afraid I don't know what they all are.

Any questions or comments from the audience?

MS. SMUTNY-JONES: I'm going to sit here so I can spread out, if you don't mind.

PRESIDING MEMBER BYRON: Go right ahead, Ms. Smutny-Jones. Turn on your microphone, please, and identify yourself.

MS. SMUTNY-JONES: Good afternoon. Robin Smutny-Jones, Director of Regulatory Affairs, here on behalf of the ISO. Happy New Year to all of you. Happy to be here today.

And would have to open with Commissioner Byron's remarks that it is, in fact, a bit early for us to make meaningful predictions about the upcoming summer because we're just getting some data in, ourselves, and our normal season for analysis is about now. So we're going to do our best to make a couple of statements.

And I'd also like to introduce an effort that we're kicking off with your staff; and had some discussions with Commissioner Byron and Advisor Ms. ten Hope. And we're excited about that. So I'll just kind of go through a few remarks here, and then I think I'm on the demand response agenda to make a couple comments there. So maybe I'll stay put in case there's questions, if that's all right with you.

With respect to forecasting in general, we have kind of gone back and forth in the past several years about how we approach things at the ISO, how the CEC approaches things. For awhile the policymakers would call us in to energy action plan meetings or what-have-you and say, well, why aren't you the same, why don't you have, you know, we expect you to come in here and really have a consistent package of information. And it doesn't quite work out that way.

And it took us awhile to explain to folks that that's okay. Forecasting isn't about right or wrong, who's right, who's wrong. There are a number of different assumptions and analyses that go into our respective assessments and forecasts.

And we believe that's okay as long as we can, together, combine our expertise and our resources to package the most useful and user-friendly information possible to deliver to you all, the policymakers at the PUC, so they can then make very important decisions about what's the proper planning reserve margin; what's the proper level of insurance. And if we have differences, what are those differences, and why.

So that's kind of the goal. And we have fiddled around with some discussions in the past and great beginnings with Ms. Bender and others, and to no one's fault there's been a lot going on and it's hard to get real excited about number crunching and spending time with that.

But we really believe it's a worthwhile effort, and I think that we are dedicated on our side. And I sense dedication on your side to take this seriously and perhaps work out some more concrete and consistent information, even by the summertime when we have to go before whoever, whether it's Energy Action Plan or whoever, to deliver that information.

So we're looking forward to that. We've had great collaboration in the past, and I look forward to that being able to continue.

A couple of examples of what I mean by that, what's different. A couple things I can pull out here.

Import assumptions and hydro assumptions. For import assumptions I'm told, I'm not the expert here, I have a couple of folks that do this day-in and day-out that I can probably call on if I need to.

But, we believe that the CEC might take an approach of looking at the transmission capacity. And if 8000 megawatts can flow through -- I don't think it can, it's more like 3500 -- whatever can flow through the Pacific Intertie, then that's going to be the import assumption.

The ISO takes a look at operationally what is feasible. We take a different approach at looking -- we have conversations with the control areas to understand what their latest fish issues are, and maybe we look at the wet database to understand what new additions have come about; how might that impact imports. That's one example.

And hydro assumptions, we have different ways of coming at that, as well. Again, not right, not wrong, just different. But what does that mean. And all of this discussion, without commenting on the actual figures that were brought out by Mr. Brown and highlighted, it kind of goes without saying that if we're going to come at different numbers with regard to import assumptions, let's just say for example ISO has an import assumption of 7000 and CEC has import assumption of 10,000, that's going to have an impact on the bottomline number that everybody likes to focus on with respect to probability of peak day events.

Right now I think you're noting .1 percent, minus 2.2 percent, .5 percent in ISO. We're currently sitting with the information we have right now, which is not including a lot of new information we're getting at something higher than that.

So, you know, this is the kind of thing that we want to be able to not get caught up in some confusion discussion with a larger group. And, you know, we just need to explain why and what those differences are. And I happen to think, I think we happen to think it's perfectly okay as long as we can explain why those differences are there. And then let the policymakers make their decisions about planning reserve margin.

There's a proceeding being undertaken at the PUC right now to look at the planning reserve margin. We're headed into an era of probablistic analysis rather than deterministic, which I think is more helpful in terms of understanding what really might happen instead of rather arbitrary look at is 15 percent right, is 17 percent right. Bottomline is it's the state's choice and the state's right to choose the level of insurance.

We want to be a partner with you and add our expertise and resources to the extent we can to complete that information for you. And, again, I think we have a great working relationship and have improved that annually, and look forward to working that with you.

I don't think I have a whole lot more to say on this particular issue for now, unless you have questions. And then I'll wait patiently for the demand response panel.

CHAIRPERSON PFANNENSTIEL: Robin, actually I do.

MS. SMUTNY-JONES: Yes.

CHAIRPERSON PFANNENSTIEL: Where there are differences in numbers I know that we can agree, those of us who look at the numbers and can, you know, make some judgments on them, that maybe these differences aren't so great, or maybe they're ones that we can understand.

But, you know, it gets sort of outside of our little proceedings when other people take this up. And they want to know whether there's a low or higher probability of outage. How much safety do we have.

And so do you have or will you have or are you able to share with us today where the specific differences are, and is the process that you mentioned that we're undertaking now designed to sort of peel back net import numbers and determine why there is a difference? And look at them in both context.

I'm just a little concerned that in the past, the last several summers it seems that we, you know, you and I and Commissioner Byron and Commissioner Geesman, and probably everybody in this room sort of knows what the differences are. We're fairly comfortable with them.

But whether it's the news media a

certain way, or gets used in some other context, other people may not have that level of comfort. But I think we need to know as soon as possible, and as clearly as possible, what the differences are and why they are as they are.

MS. SMUTNY-JONES: You could not have said it better. I just had some conversations with Laurie about this, that we need to start from the top. What are these forecasts being used for. We need to really understand what they are being used for.

And then we need to understand how we generally have come about things. And I think the biggest challenge might be how do we present it. How do we articulate some very complicated issues and assumptions and the nitty-gritty things that go into the assumptions in a way that makes sense for the Legislature and the Public Utilities Commission.

I just had an MRI yesterday on my shoulder. Believe it or not, as I was in the machine I was thinking bout this. Isn't that sad? I was thinking --

(Laughter.)

MS. SMUTNY-JONES: I was thinking about

how, you know, when you plan this system and make it useful, if you can have the information that an MRI gives you, rather than an x-ray, you probably want to take that.

Got to look at expense. MRIs are a lot more expensive. But you want to take the most complete set of information that you have and make the most use of it.

And I think to your point, very clearly articulate what that information means so that when it -- and understand how it's going to be used, so we can all be on the same page.

So I couldn't agree with you more. We're planning a meeting in the next -- we talked about trying to get this in the next couple of weeks. First we've got to line up our resources. What else do we have to do. And then come up with the best plan we can, so that possibly even by -- usually there's some May or June kind of we all get together and say, all right, what does the summer really look like, after having the benefit of understanding snow pack and, you know, do we have any pineapple express issues out there. And hopefully not too many dry spells. All those kinds of things.

So that is the intent. And I appreciate your articulating it better than, I think, I did.

CHAIRPERSON PFANNENSTIEL: Thank you.

PRESIDING MEMBER BYRON: Okay.

MS. SMUTNY-JONES: Any -- you want to --

PRESIDING MEMBER BYRON: Yes, sure, go right ahead. Thank you, Ms. Jones.

MS. SMUTNY-JONES: Thank you.

PRESIDING MEMBER BYRON: Please identify yourself.

MR. ALVAREZ: This is Manuel Alvarez, Southern California Edison.

PRESIDING MEMBER BYRON: I don't think your microphone is on, is it?

MR. ALVAREZ: The green light's on.

PRESIDING MEMBER BYRON: Okay, there it is.

MR. ALVAREZ: Manuel Alvarez, Southern California Edison. Actually came up now because I want to follow up on Robin's comment. Because I've also done a lot of thinking about the issues that Commissioner Pfannenstiel raised, and the perception of conflicts that --

PRESIDING MEMBER BYRON: How's your shoulder? Is your shoulder okay?

(Laughter.)

MR. ALVAREZ: I deal with heart issues as opposed to shoulder issues, so collecting data from various technicians is definitely part of my equation now.

But, I guess, you know, if I was going to follow the analogy, I guess I'd like to take the data, the information from the x-ray technician in addition to the MRI technician and put them before you. And neither one of them is better. It's who then analyzes that data and then what implications can they identify and discover the problem that you're trying to solve.

So I think you want to kind of keep that idea in place as you think through. This is a bit of an issue that's going to get teed up again in the IEPR for the next cycle, because the forecasting complexities and dilemmas that we faced last time, I don't think have disappeared from the equation yet. And we're going to confront them once again.

But, I think you want to hear from as many analysts as possible. And I've tried to push this issue about finding the right forecast, and it just doesn't seem to work. You want to hear from the various analysts.

You don't want to stymie their creativity and their analysis and their insight that they bring to you, but you need to kind of -- I refer to it somewhat as a consensus. At some point you're going to have to drive something to a consensus, but I'm not sure I like that word because of the implications it brings in in this process. But you definitely are looking for something by which you can wrap your arms around about the best view at that particular time and say, this is what we want to advance forward at the PUC, at the CEC and the State Legislature.

But I want to caution you. I personally don't feel comfortable with the word consensus yet. But there's something out there that we need to drive to in this forecasting process to get to. And I'm not sure I have that answer yet. But it's definitely something that will be a subject of our discussion down the road in the next IEPR.

So, I just wanted to add that because the topic came up. Thank you.

MS. SMUTNY-JONES: And a quick clarification. I agree with the consensus may have been pushed by policymakers sometime back in

EAP. Maybe a couple of you were one of them, I don't know. But to say, can't you come forward with one number and make our jobs easier and give us, you know, we want one number so we can understand.

And I think we slowly started to educate ourselves and others that that's not necessarily what you want. Forecasting is forecasting. It's a guess, you know. If someone was going to be right all the time, they'd probably be a very rich person and they wouldn't be, you know, in this particular business in this room.

But if you have the CEC say there's a, you know, 2 percent likelihood of stage 2 or whatever, and the ISO's at 1.5 percent. And we're looking at all kinds of different information, it's kind of cool to be able to think, well, they're coming at it from completely different ways, and yet we're pretty close.

So it's check-and-balance maybe kind of idea. That's just one thought to keep out there.

PRESIDING MEMBER BYRON: If there's no further comments we'll go ahead and move on. Thank you.

MS. MARSHALL: Hi, I'm Lynn Marshall; I

work in the demand analysis office here at the Energy Commission. And I'll talk a little bit about the forecast that's used in the supply/demand outlook and some initial analysis we've done of last summer as an evaluation of how well our forecast for 2008 looks right now.

So, while it's early for the operators to start looking at supply/demand assessment, for the purposes for which the CEC forecast is used, primarily in the year ahead resource adequacy process, we actually have to develop our forecast early last summer.

So this was developed initially in our staff forecast of 2008 peak demand where we looked extensively at 2006 loads and temperatures.

And that analysis essentially served as the starting point for our long-run forecast. So, following that we updated our ten-year forecast in which we forecast energy consumption for each of the utility areas within the state using our sector models.

And then from that we derive a peak forecast and we incorporated most recent population forecasts and economic forecasts and updated some of our other assumptions.

But when you're forecasting near-term peak demand, the growth rate of the forecast tends not to change from vintage to vintage of forecast. So what really drives our year-ahead peak forecast is a starting point. And that's driven heavily by what you assessment is of your most recent peak demand. So where you are now determines where you think you're going to be a year from now.

And in recent years we've compared our forecast with the utilities, resolving differences about that starting point, the weather-adjusted starting point has been the critical issue in the near-term peak forecast.

So, we have, at this date, only some limited hourly load data that we used to do this analysis, so we have the hourly loads for each of the ISO's TAC areas, so that's NP-15, the Edison area and San Diego. We're still working on our San Diego analysis. They've actually peaked on a weekend or a holiday two years in a row now. So it makes the analysis a little more complex. But we'll look at the ISO as a whole, and our NP-15 and Edison area results.

So this table summarizes what our forecast was for last summer, and the observed and then our weather-adjusted. So, for what we see so far, we'll do more of this analysis in more detail with individual load-serving entity hourly loads, but right now it looks like our forecast is consistent with the loads we observed last summer for both NP-15 and the Edison area.

I'll say a little bit about how we do our forecast. We don't do an ISO forecast. We do the Edison planning area. We do Pasadena, we do DWR, PG&E; and then for Edison and PG&E we're actually forecasting for climate zones within those areas. And then we aggregate them up and match them to control areas.

And for north and south we assume a diversity factor of about 2.5 percent. So that's a coincidence adjustment that, on average, north and south tend not to peak at the same time. I looked at the diversity in '07 and that's about what happened. In 2006 it was much lower. So, that's an assumption that can affect the accuracy of the ISO forecast.

So, here's a summary of the results we have so far. And as I said, the '06 to '07 weather-adjusted growth rates are overall in line with what we were forecasting. And I'll just go through it -- well, first of all, I'll explain our methodology for how we do the weather adjustment, and then we'll just go through the graphs that illustrate our results.

So, we have, when we're doing weather normalization we're trying to predict peak demand as a function of temperatures. And we use weighted -- we weight temperatures by the distribution of the saturation of air conditioning in each of our climate zones.

And then for southern California we use a second variable, daily maximum minus the daily minimum that reflects the temperature spread. And so we're estimating the temperature response of peak demand, how high -- how much peak demand goes up as temperature increases and the temperature spread decreases typically.

We also get the reported demand response and interruptible effects that are reported by the utilities, and add those to demand. So, we're weather adjusting the internal demand, not the recorded demand.

So our maximum temperature variable, it's three-day weighted; 60 percent today, 30 percent yesterday, 10 percent the day before that.

So we're capturing the effective heat buildup. And you can see those are the weights for each of the utility areas.

So we've got five weather stations for PG&E and four for Edison. And then, as I mentioned, we have a second temperature variable for Edison that captures the temperature spread that's highly correlated with humidity and it also picks up the heat buildup effect when you have no cooling at night, and the temperature spread is very low.

So, here is the ISO as a whole for this summer. And we have -- the dark blue line is what actually happened, and the pink line is what our weather statistics would predicted using our weather results -- weather model from estimated from 2006 loads.

And on the whole it looks pretty good. We're tracking pretty well. The mean average percent -- absolute percentage error is about 2 percent for the summer, as a whole. And you can see the peak event there, just before the -- it's just around the holiday weekend at the end of the summer. And actually think the peak temperatures were on the weekend there. So we could have had higher demand had the temperatures peaked a little later.

So here's the actual temperatures. So you can see the temperatures actually went up to almost to one-in-ten on the weekend, but on Friday they were not much above one in two. There's a difference there north and south.

Now, this is the same -- so we're a little above one in two. This is the same data compared to 2006. So that pink line is the 2006 daily temperatures. And you can see, it was a lot hotter in '06. We all knew that. So in '06 we were at above a one-in-ten, and here we're not quite below.

Looking at controlling for temperature, so this is a scatter plot where we're plotting temperature versus demand, so it gives you a basis for comparing the loads from year to year. And so the pink line, the pink points, are 2007. And it's a little higher than '06, but not a whole lot. So that shift up represents load, you can think of that as baseload.

It doesn't look like the slope is a lot steeper. If the slope were steeper that would be even greater temperature response in addition to baseload. So, as we said in the summary, so it looks like load growth of about 1.5 percent, about in line with what we were forecasting.

Going back to, as we said, '06 was a lot hotter than '07. And this is the top end of a load duration curve, so this is the top 100 hours sorted in rank order. And you can see the effect of the higher average temperatures in '06.

You had -- on '07 there were only nine hours over 47,000 megawatts and only about 20 hours over 45,000 megawatts. And compare that to '06 where we had something like 60 hours over 45,000 megawatts. So, big difference in the load duration curve at the top end. We don't have all 8760 for both years, but those load duration curves flatten out, so they're right on top of each other as you go farther down.

Okay, looking at NP-15, these are the temperatures for the PG&E area. PG&E had two hot weather events, but both of those were below a one-in-two; essentially their peak ended up being the same in both of those periods. And these are the scatter plots for NP-15.

So, again, the same story is the ISO 2007 slightly higher than '06. Kind of a slight shift up in demand. Our estimated weather-adjusted peak is essentially the same as our '07 forecast.

Now, again, this is NP-15; this is PG&E and DWR and NCPA and Silicon Valley all lumped together. And as we get the individual load data for each of those LSEs we'll look at it in more detail and get a better read on it. So our end results might change.

And here is Edison area, summer temperatures for '06 and '07. And Edison, much hotter; and you can see that holiday weekend they were over a one-in-ten. So, the last weekday, Friday, August 30th, they were about a one-in-five, so that ended up being their peak day. Would have been, if we'd had the weekend temperatures occurring earlier, you'd had a much higher demand.

And here's our scatter plots for '06 and '07. This is a little misleading because it doesn't account for the effects of the daily spread variable. But it gives you a sense of what the load temperature relationships are.

The weather-adjusted peak is actually lower than our '07 forecast. I think that's largely because DWR's loads were a lot lower than we assumed in our forecast. We assumed their average pumping loads based on what we observe in an average water year.

So their average onpeak loads during the summer in an average water year. And obviously that was probably high for last summer. And also there's generally kind of voluntary curtailment on the part of DWR when their resources are needed. So that tends to show up on the coincident peak.

And there are two -- in those slides I realize we didn't show anything about how we derived the one-in-ten. So those were our -- just two more slides -- so that's our one-in-two. Our one-in-two is based on the median temperature. And we're using a historical dataset, 1950 to 2007.

So we estimated our load temperature relationship and used the median temperature for the one-in-two. And then the one-in-ten is the temperatures at the 90th percentile.

So you can see on here, our one-in-ten is the black dashed line up there. Now, another methodology that some utilities have suggested we should look at is rather than using just this as a population, assume this is from a normal distribution. That would give you a slightly lower one-in-two, but it would give you a higher one-in-ten.

PG&E, right now, we have a one-in-ten multiplier of about 3.5 percent. Part of that is because PG&E is a large area; it's geographically diverse. So, if you look at the historic distribution relatively few events we would have -- we've observed at that higher range compared to the Edison area. So I think that's a methodological issue we'll probably continue to discuss with PG&E.

Here is the temperature distribution for Edison. You can see 2007 way up at the upper end. And, again, we show a couple of different ways of calculating the one-in-two. So our one-in-two is that lower blue line.

If you use a shorter data series, if you throw out the first three years of data, you can get a higher one-in-two. I think if you put 1990 in there you could get a lower one-in-two.

So the estimates of the one-in-two and the one-in-ten are really sensitive to the methodology you use and the assumptions you use.

Our current one-in-ten multiplier for Edison is, I think, 8.8 percent. That would be higher than if you assumed we were drawing from a normal distribution and used that other statistic.

And so that's all I have. Any questions on this?

PRESIDING MEMBER BYRON: Ms. Marshall, why is it that we use all the data that we use? Is that because we've got that full dataset?

MS. MARSHALL: That's as much data as we have. And so every year we get another data series we add it. So we use the weather stations we use because they're the ones for which we can get data all the way back to 1950.

Some of the utilities would probably argue in a reasonable case that there are other weather stations that fit their utility loads better. But they don't have nearly as much historic data. So it's a tradeoff we make in terms of having a longer historical perspective and fitting the load data.

I think Edison uses a shorter history, but they have different weather stations and they don't have as much history available.

PRESIDING MEMBER BYRON: Following the

July 6, 2006 heat storm, coincident with Al Gore's movie being out, there were a lot of folks that thought we'd be in for warmer, you know, statistically warmer summers going forward, and more extreme events.

Is there any way that you think our data should account for that possibility?

MS. MARSHALL: You know, we haven't seen it in -- there hasn't been an obvious trend on the peak temperatures. And, you know, that may be true if you look at average annual temperatures. But on the annual peak you haven't seen that.

On the other hand, there are datasets that are being developed as part of the global climate change analyses. They have downscaled temperature datasets that would predict temperatures under various climate change scenarios.

The most recent study that I saw on those reported that while they were doing a pretty good job of predicting winter temperatures and average temperatures, they were systematically over-predicting peak.

That's obviously a problem for, you know, doing a peak demand global climate change scenario.

So I think it's something we want to look at, but we also need to look at whether we have a plausible temperature scenario.

PRESIDING MEMBER BYRON: Okay. Well, I'm not sure there is an answer for that question. And, with regard to all the data that you've got here, forgive me but I'm going ask the direct question about what about 2008.

MS. MARSHALL: Well, from the analysis we've done so far, our 2008 forecast looks reasonable. So we don't see any reason to change the forecast we have out there now.

PRESIDING MEMBER BYRON: Okay. Any other questions from the dais? All right, let's open it up then to any questions from the public.

All right. Well, there'll be more opportunity.

Ms. Marshall, anything else?

MS. MARSHALL: Nope, that's it.

PRESIDING MEMBER BYRON: Thank you very much.

We may have Chairman Pfannenstiel back. I understand she has an obligation at 2:00, but I don't think we'll see Commissioner Geesman. He's hopping an airplane to Washington, D.C.

(Pause.)

MR. HUNGERFORD: Good afternoon. I'm David Hungerford; I'm with the demand analysis office. And I work on demand response here at the Energy Commission. I'm here to talk about demand response projections for next summer.

We're going to do three things here. One of them is we're going to talk about our impact expectations, and this is the -- we'll go into more detail on the slide that was at the end of Denny Brown's presentation that Commissioner Pfannenstiel asked about a little while ago.

We have some guests from two of the IOUs, Edison and PG&E. AnD I believe SDG&E is on the phone, and from SMUD, to talk about their demand response programs and their triggers.

And then we'll briefly talk about a proceeding that we're opening here at the Commission on load management.

First we'll go to the impact explanation. So this is a rather busy slide, but it does lay out -- a little bit hard to read for the people in the audience -- it does lay out the programs that all of those acronyms stood for in

Denny's table. And it lays it out by the three IOUs. We don't have the publicly owned utility numbers in here, although in the future we will be adapting to incorporate that.

If you look at each one, each of those boxes are roughly parallel, although there's some differences between the programs across the utilities. And there are fundamentally two different types of programs, or two different categories of programs that we use.

One of them is what we call price responsive programs which are triggered on a day-ahead basis, and essentially function to reduce the forecast for a peak day. And so they're triggered in anticipation of a peak load day.

The others are what we call emergency programs or reliability programs which can be triggered under various conditions with a relatively short response time. And we call those day-out programs.

And looking at these lists, the AC cycling, the smart AC programs, looking at PG&E's list, would be an example of a day-out program. And the base interruptible program, our traditional interruptible rates where customers get a rate discount in promise of a load reduction during an emergency. Our example is another example of the day-out program.

The pricing programs are the peak pricing tariff, demand bidding program and some of these others.

There's another thing we do with these. We derate them. There has to be some way of counting how many megawatts are in these programs. And especially when you consider the price responsive programs, it's difficult to predict how much load a customer might drop on a particular day in advance, because their response is voluntary.

They're facing a high price during the peak period, and there may be some times when they can drop a substantial amount of their load; and other times if you think about an industrial customer who may be in the middle of a particular process that they can't shut down, where they can't drop as much load.

And so the only way to really predict what's going to happen with the price responsive program is to build a history of experience with those programs; observe what customers are able to drop, or customers who are participating on this program, drop and make a statistical prediction of how much load you'll get on a particular day. And these de-rations are based on that kind of experience.

If you're counting how much load, if you're trying to figure how much load you have available to you in a pricing program, you're faced with having to count somehow how much a customer is bringing to the table.

And one way to do that would be to count their total peak demand as measured by their historical consumption. And say, okay, that customer, their total load on a hot day is 100 megawatts. It's clear that they're not going to drop all 100 of those megawatts. They'll drop some portion of that. And so you can count it that way.

I believe the way most of the utilities are counting their critical peak pricing program is they made an assumption that something on the order of 30 percent of the customers' peak demand would be dropped, or could be dropped potentially, on a peak day.

And, in fact, when we look at the

response to the programs we get actually a somewhat smaller number.

And so their enrollment number is roughly, if I -- David, is that correct, roughly 30 percent, was that the multiplier?

MR. REED: We used 15 percent --

MR. HUNGERFORD: Fifteen percent.

MR. REED: -- (inaudible).

MR. HUNGERFORD: Okay, so the -- looking at SCE, the 3 megawatts in projected enrollment is actually 15 percent of the total demand of the customers in that program. And then that actually ends up working as a multiplier.

So, these de-rations in the second column are actually ways of putting the real data to the enrollment numbers and predicting what we'll actually get during the peak event, based on history.

And we now have -- we're moving into our fifth year of the more recent price-responsive programs. And so these numbers are actually stabilizing. They vary a bit. We do adjust, based on experience, year by year. And the utilities may do it a little differently than we're doing it, but we and the Public Utilities

Commission have worked out a set of de-rations which are listed in that column which we feel are fairly accurate.

All right. There are also a number of things happening, and recalling that that both Denny and Lynn have described, that our forecasts for this workshop is based on data from last year, which is the best we can do.

There are a number of changes that have happened to the demand response programs that could affect these numbers for this coming summer. But we're not certain what they are. And so the utilities are actually going to update us on that a little bit later.

As a result of the heat storm of the summer of 2006, the PUC authorized the utilities to make some changes to their programs. And directed them to develop some additional programs to try to build the demand response capability. And the decision wasn't out until very late in 2006.

The utilities got going, trying to put some of those things together by the summer of 2007. And got something going by that summer; got some enrollment in some programs; made some changes in their triggers. And some of that is reflected in the numbers on this graph.

However, a lot of the things that they were doing, especially the development of the new programs, weren't approved until fall of this past year. And so we're going to see some additional demand response this summer that's not reflected in this table. And that's one of the reasons we asked the utilities to come, is to tell us about what they've been able to accomplish over the past year; what their enrollment, the new kinds of customers, and their expectations for these new programs.

All right, and I think at that point we can move on to asking the members of the utility representatives who've come to help us out today to come up to the table, if you'd like. We have Osman Sezgen from Pacific Gas and Electric Company. We have David Reed from Southern California Edison. We have Gary Lawson from SMUD.

And I hope we have Mark Ward from San Diego Gas and Electric on the telephone. Can we verify that we have San Diego on the telephone?

(Pause.)

PRESIDING MEMBER BYRON: Mr. Hungerford,

may I ask you a question?

MR. HUNGERFORD: You may.

PRESIDING MEMBER BYRON: Going back to your DR impact expectations table, the de-rated column where you have your factors, I can't help but notice that Southern California Edison's factors for the AC cycling and the critical peak pricing are both 1s. And I was hoping you might explain to me why they get full credit for those; they must be very successful at those programs.

MR. HUNGERFORD: Edison reports two different numbers when they file their reports with the Public Utilities Commission on a monthly basis for their programs.

They report an enrollment number and they report an expected number in which they apply their own de-rations to those programs.

PG&E and San Diego Gas and Electric report only an enrollment number.

So the reason that those factors are 1 is that Edison has already done their own de-rations of those numbers. And they just report slightly differently. So I wouldn't want to criticize SDG&E and PG&E as being less productive in their programs than SCE is at this point.

PRESIDING MEMBER BYRON: All right.

MR. HUNGERFORD: They just report in a different way.

PRESIDING MEMBER BYRON: It's an artifact of the reporting.

MR. HUNGERFORD: That's correct.

PRESIDING MEMBER BYRON: Okay, good. Thank you.

Well, welcome, everyone. Thank you for being here today. How should we proceed? Should we go left to right here, is that all right?

MR. SPEAKER: Your left?

PRESIDING MEMBER BYRON: My left, please.

MR. LAWSON: Gary Lawson, Sacramento Municipal Utility District.

MR. HUNGERFORD: Okay, I'm going to pull up your presentations, Gary.

MR. LAWSON: Oh, sure. And if you'd go to the last slide, that's got our demand and load response table.

MR. HUNGERFORD: That one?

MR. LAWSON: Can everybody see that? I apologize if you can't.

This is our set of expected programs for our 2008 upcoming demand response programs. It's pretty much a status quo set as compared to last year and the last several years.

I'll go ahead and explain them. We've categorized them into two categories, dispatchable and nondispatchable. Dispatchable primarily means where we have the control to either -- on a device to shut it off or to request a customer to curtail load under contract. The nondispatchable are really customer response and voluntary programs.

Going down the dispatchable list, we have our grandfather of load management programs, residential air conditioning load management. We have a range that we rely on internally for our planning. The low end of the range, 97 megawatts, represents a normal cycling event where we're cycling customers at the cycling strategy they enrolled in for the program.

And we had 50 percent, 67 percent and 100 percent cycling strategies. The 100 percent being where we can completely shut off a customer's air conditioner.

The 130 megawatt number is what we use for emergency planning. And that's where we literally shut off all participants' air conditioners. And we would only do that in an emergency, system emergency condition.

The industrial curtailment, we have a couple customers under contract where they have contractually committed to curtailing up to 12 curtailment events in any given calendar year. And this represents the load available to us under those curtailment requests.

We have the ability of notifying those customers, in the case of one customer in the morning for an afternoon curtailment; in the case of the second customer, we can give them ten minutes notice and they'll have their load off within ten minutes.

So, the range of expected is 111 to 149. We've recorded 147, I think, in our last year form S1 filing to the CEC. And so those more than likely are numbers that your staff is using.

Our left column represents our current perspective of the performance of the programs.

For the nondispatchable programs, we have three. We have one rate response program similar to a critical peak pricing. We call it our temperature-dependent rate. Effectively the customers on that rate will receive a notice on a day-ahead basis when our expected day-ahead peak temperature is 95 degrees or higher. In that event, the rate for the subsequent day will be a super peak, critical peak pricing type of rate. But they know ahead of time.

We'll either get no response, or some response from the customer, based on whether they either are constrained in their production and must produce, or can actually respond to the price signal.

Our demand bid program is a program where our utility trading division in the morning in advance of an expected extreme peak situation would post a price of power we'd be willing to pay for load curtailed by the customer. And it's based on effectively a wholesale energy market price.

Typically we don't see a lot of activity or response to those prices. The only time we've sen activity is when we've posted very large prices. And so we, similar to what it looks like, the investor-owned utilities, we don't have a high expectation of participation on any given day with this customer or this program.

Our voluntary emergency curtailment

program is a completely voluntary program that our commercial account representatives approach commercial customers who have significant enough loads to do some curtailment on.

And in that program they enlist or enroll themselves to volunteer to shed certain loads in their facilities when called upon by SMUD. And, again, it's completely voluntary.

The way it operates, SMUD has an automatic dialing notification system. If our system dispatch staff determines there's a need for this load curtailment, they'll have the program people initiate automatic phone calls to customers. And we can see response within about an hour of initiating the program.

Again, it's completely voluntary. The 45 megawatts is the maximum load subscribed to under that program.

For our nondispatchable programs, while we expect anywhere between zero and 61 megawatts, we've reported 53 megawatts in our CEC form S1 to represent our expected performance and any de-rates in customer response.

I can answer any questions.

PRESIDING MEMBER BYRON: Well, that adds

up, it's a nice round number.

MR. LAWSON: Yes.

PRESIDING MEMBER BYRON: And just out of curiosity, what percent of that is -- what's that percentage of your peak load, then?

MR. LAWSON: SMUD's peak load is around 3700 megawatts. And that's the SMUD -- that's not the SMUD control area, that is the SMUD load-serving entity.

PRESIDING MEMBER BYRON: Okay, I can't do that math easily; 200 divided by about 3700. Thank you.

Okay, Mr. Hungerford, any questions for Mr. Lawson?

MR. HUNGERFORD: No. Thanks, Gary.

PRESIDING MEMBER BYRON: Thank you.

MR. REED: David Reed, Southern California Edison. Good afternoon. I just had a couple of slides. First I want to just go over where we are today in terms of enrollment and what activities we have underway -- the numbers for 2008. And then the second slide is a kind of a summary of the program operations, which I can voice-over a little bit what we actually do.

MR. HUNGERFORD: David, is this the

correct presentation?

MR. REED: Yeah. So if we go to the first chart, as of the end of 2007 we had 1321 megawatts of curtailable mode. And as David Hungerford mentioned, we do our own de-ration; look at historical performance on these programs that we've seen. We take pretty drastic -- maybe drastic is not the right word -- but we do de-rate the price-response programs and modes.

Our interruptible programs are very reliable and there's also a lot of penalties involved if customers don't respond. So the performance there is very high.

The critical peak pricing, we do have as of this end of 2007, our price response programs are 50 megawatts. The only program we've really not de-rated on this chart is the Interlock (phonetic) contract. We just signed them up; they just started ramping up in July. And we've only had three events. So there's really not enough experience there to make a judgment yet.

But based on December 2007 we had 50 megawatts for price response programs. For summer 2008 we are intensifying our marketing for critical peak pricing, so expect some bump there.

Also, the 16 megawatts for demand bidding is based on 2006 performance. And we've not updated it for 2007 yet. But, in fact, we had probably double the participation in demand bidding this last summer. And we signed up some big customers that have made much more significant load reductions for demand bidding events. So, in fact, that 16 megawatts should probably be closer to 30 megawatts.

Also Interlock contract is ramping up contractually next summer to 40 megawatts. So, you know, we'll see how they perform. But, in fact, if they're going to come up to 40 megawatts, and we bump up demand bidding, we're really closer to 90 megawatts for price response next summer. And that's not counting the pending application we have for DR contracts for 2008.

The Utilities Commission is going to make a decision on that at the end of February. If they approve those contracts, we'll have more price response DR in 2008. So we are making progress bumping those numbers up.

For the interruptible programs I think you're probably familiar with the base interruptible and air conditioner cycling. And we have an agricultural program, as well.

There, you know, we had a significant growth in air conditioner cycling over the last year and a half. We've added over 225 megawatts there. So, it's really bumped up a lot.

And we've retained most of our BIP and I-6 customers throughout the crises in the last few years. So we haven't lost too many there. So we're over 600 megawatts, as well.

And, again, we do de-rate the BIP and I-6 slightly because occasionally customers for whatever reasons don't curtail. But again, there's significant penalties if they don't. So they're pretty reliable.

Air conditioner cycling, as David was alluding to, we don't have metering on the end use, you know, the air conditioners. So we basically rely on statistical analysis for what load drop we expect from air conditioner cycling in various temperatures. So this is what our grid control uses to estimate what load reduction we get during interruptions. So those are pretty good numbers.

We do have internally plans, and we've allocated funding for the -- that we've been authorized by the Utilities Commission to increase the summer discount plans, air conditioner cycling next summer. So we're looking at adding up to 84 megawatts next year for summer discount plan by the end of the year.

So, you know, if you kind of take half of that by this summer, because a lot of times we still get enrollments past the summer. Our interruptible programs, I would estimate somewhere around 1300 megawatts. So for the summer we're probably looking at closer to 1400 megawatts of curtailment.

That's compared in total to, I think, the CEC Staff estimate of 1200 megawatts. So CEC Staff was a little conservative, so that's okay. But I think they're around 1200, we're 14.

On the second page, or the second chart, is really just a kind of itemization of our programs and how we call them, and what categories they are.

Critical peak pricing, demand bidding, capacity bidding and our Interlock contract we all consider price response or demand response. And they mostly day-ahead, in the sense that we determine if we're going to call the event a day-ahead and we notify customers a day ahead, obviously.

We do have some features for demand bidding as of the day-of. And for capacity bidding a day-of, as well. And our Interlock contract has a day-of feature.

We have, in the tariffs for all these programs, we have what we call soft triggers. In some sense we have kind of a menu that triggers, but temperature, system conditions, wholesale prices and so forth.

But what we elected to do this last summer is to really kind of make it a little bit more consistent across the program. So our procurement folks wanted to use a 15,000 Btu heat rate as the basis, a proxy for price. So, in fact, when they forecast on a day-ahead basis a 15,000 Btu heat rate we determine, we decide to launch the program for the next day. So there's some consistency there.

In fact, and just from experience, last year we called critical peak pricing 12 times which was a tariff requirement. We called capacity bidding and demand bidding around 20 times each.

And our complex, as I said before, our Interlock contract we only called a couple of times this last summer. And the Interlock contract it says that SCE discretion. Our procurement folks want to use that when it's in the money, as they say. There's a strike price, I think, at $300 per megawatt hour. And when they receive forecasts, however they do it out there, they launch that program.

The difference -- the next group of programs are interruptible programs. The difference in terms of launching those is our procurement folks launch the price response programs. The interruptible programs, our grid control launches those programs. And, in fact, they have buttons that they actually push for those.

On the interruptible programs our grid control works very closely with the ISO in terms of determining what programs to launch and how many megawatts that we actually need. In fact, during periods when there's issues with generation supply, I think they're on the phone -- I think John Gooden can confirm that -- I think they're no the phone during that day and the day before to insure that everybody's coordinated. So there is that coordination there.

And, again, the BIP and I-6 and air conditioning cycling programs are launched on a stage 2, or transmission emergency. We have those customers, the BIP and I-6, have 15 minutes, if they elect to do that, or 30 minutes to drop load. So it's a fairly quick response.

The summer discount plant, or the air conditioner cycling, in fact, the grid control pushes a button there, and the air conditioners begin to cycle within ten minutes or less. So it's a much quicker response.

And ag pumping, agricultural pumping, is another load control program that's launched by stage 2. The one nuance on the air conditioner cycling, we do have limited capability to launch those programs by district or substations. And, in fact, there were six events for air conditioner cycling this summer. And I think most of those were those hot days over Labor Day that Lynn was talking about, where we had substation transformers that were starting to blow, whatever.

All these programs are available in the summer. They're all summer programs.

So that's basically it.

PRESIDING MEMBER BYRON: Very good, thank you. If I may ask a quick question. Your table shows -- the first table shows a total capability at the end of last year around 1321 megawatts, and I believe you indicated that you expected it to be around 1400 megawatts by the summertime.

You know, this is tremendous. It's great growth of the demand response programs. If I understand, Mr. Hungerford, we're using a number that's slightly less than 1200 megawatts for Southern California Edison service territory. That's a difference of about 15 percent by my math. Do you want to --

MR. HUNGERFORD: Which reflects the growth in the programs that SCE has been able to accomplish since last summer, or towards -- since the numbers that we used were developed, until next summer. This is their projections based on the new enrollment and the new programs that were approved last year.

And so we're aware that those programs are being developed, but --

PRESIDING MEMBER BYRON: And I know

we've taken a conservative approach. We wait for enrollment, we wait to see what happens, we wait to see how successful these programs are.

Will there be an effort to reconcile these numbers and update our forecast this year? Or are we going to hold the numbers we've got?

MR. HUNGERFORD: I can ask Lynn to -- it's your forecast.

PRESIDING MEMBER BYRON: You can answer later because we've got a few more service territories to go through. We'll see how significant it's going to be.

MS. MARSHALL: Right, I do have to talk about that. There was not --

PRESIDING MEMBER BYRON: You need to step up to the mike. Thank you.

MS. MARSHALL: We developed these numbers last summer so they could -- we developed these last summer so they could be used in the year-ahead resource adequacy process.

PRESIDING MEMBER BYRON: Right.

MS. MARSHALL: For this spring the next thing we have to do is actually develop a 2009 DR forecast. So actually part of that could be an updated 2008. So, you know, it's something that can be developed. It's not something we're working on right now.

PRESIDING MEMBER BYRON: All right. Well, kudos to Southern California Edison. And we encourage you to continue to grow these programs. But, we'll at least footnote that for now, that there's 200 megawatts that may be there that we're not including in our accounting.

MR. HUNGERFORD: Well, I think we'll find that we have the same kind of thing going on with Pacific Gas and Electric and with San Diego Gas and Electric for the same reason.

PRESIDING MEMBER BYRON: Yeah, that's what I thought. Understood.

MR. HUNGERFORD: There were, in fact, a number of these new contract programs where the utilities are contracting with aggregators to develop particular types of demand response programs are all fairly new. In fact, PG&E's is still up for approval right now, and a final decision hasn't been made, if I'm -- unless I missed the decision.

So, we'll see a few hundred megawatts, actually, extra --

PRESIDING MEMBER BYRON: Okay, and

that's --

MR. HUNGERFORD: Extra --

PRESIDING MEMBER BYRON: -- and that's fine.

MR. HUNGERFORD: -- extra megawatts are good.

PRESIDING MEMBER BYRON: This is not a criticism. This is really an explanation as to why we see some of the differences that we see.

MR. HUNGERFORD: That's right.

PRESIDING MEMBER BYRON: Yes, Ms. Jones.

MS. SMUTNY-JONES: In the interest of overall reconciling and trying to work together on this, can I just ask a question? Are these new programs, putting aside the interruptibles, the other new programs that are being signed up, are there penalties for those, as well, if they don't show up?

MR. REED: Yes, there are.

MS. SMUTNY-JONES: Okay, so there's no discounting that needs to happen or anything as far as we know. Okay.

PRESIDING MEMBER BYRON: There are financial penalties, right? There's no retribution here, right?

(Laughter.)

MR. REED: Their capacity payments are reduced. I think it's down 75 percent. At some point, I don't recall the exact number, they start paying us back with actual penalties.

PRESIDING MEMBER BYRON: Thank you. Did you want to present -- were you going to go through this other slide that you've brought, or was that for later?

MR. REED: I think that's it --

MR. SPEAKER: We'll do that later.

PRESIDING MEMBER BYRON: Okay, that's fine.

MS. ten HOPE: Can I ask a quick question?

PRESIDING MEMBER BYRON: Please, go right ahead.

MS. ten HOPE: I'm not familiar with the Interlock contract. Can you explain what kind of demand response program that is and how it differs from the critical peak pricing --

MR. REED: Well, critical peak pricing is a tariff for retail customers. Interlock contract, Interlock actually has its own programs with customers that it signs up. And as I understand, most of them are chain accounts. And it is very similar to the capacity bidding program where there is a capacity -- it basically has a nominated megawatts each month. And we pay them with capacity rate times that. And then if we actually call the event, we pay them, I think it's -- actually, I can't say that, I think it's confidential.

(Laughter.)

MR. REED: We pay them an energy incentive, as well, if we actually launch the event. And it's just very similar to capacity bidding. It's a year-round program, though.

MS. ten HOPE: And coordinated by an aggregator, so that --

MR. REED: Yes, an aggregator.

MS. ten HOPE: Okay.

MR. REED: Yeah.

MS. ten HOPE: Thanks.

PRESIDING MEMBER BYRON: Any other questions for Mr. Reed?

Mr. Reed, thank you very much.

MR. HUNGERFORD: I'd like to move on to Pacific Gas and Electric. And Osman Sezgen will be speaking for PG&E today. Thanks for coming, Osman.

PRESIDING MEMBER BYRON: Good.

MR. SEZGEN: Good afternoon. This is Osman Sezgen from PG&E, together with Bill Tom. We're going to talk about the programs in general, their features and a comparison of our expected megawatts this coming year relative to CEC numbers here.

Our programs -- again David Reed went over their programs -- pretty similar. I'll just go over them very quickly. They're the price-sensitive programs in the first block there, on the screen, followed by the reliability programs.

And the first couple of lines, the demand bidding program and the critical price peak pricing programs are programs that are run by PG&E. And the others, business energy coalition program, capacity bidding program, aggregator-managed programs and DWR contracts are third-party either run by aggregators or third-party contracts.

The purpose of this table is twofold. One is, again, the second column describes the calling features of these programs. And, in general, the PG&E programs are either called by like in the CPP, a forecasted day-ahead temperature, a high temperature; or some kind of California alert, notice or warning, or the load in the area being forecasted more than 43,000 megawatts.

Generally the third-party programs are run based on an economic basis, and then they're tied typically to a 15,000 Btu per kilowatt hour heat rate. And, of course, the emergency programs are based on some feature, stage 2, typically a stage 2 or a similar trigger.

Relative to the numbers that CEC presented here, which are based on our numbers a few months back, we have made some changes to reflect the current outlook. One of them was related to the smart AC program.

If you go down under the reliability programs, we had a current settlement agreement with TURN and DRA where we are limiting the rate at which we are going to install smart meters, AC cycling switches, and thermostats to our customers.

And our previous forecast was that we would get 96 megawatts by summer of '08, and then we have agreed, at least in that settlement, to limit that to 78.

So, going back, the number for PG&E that CEC showed was 884 megawatts. And I'm talking about reductions on that, that we're predicting. So we'll be getting 20 megawatts less out of our AC cycling programs. And then this is before the Commission. There's not a decision yet on that.

Another area where we took some reduction was the responses to CPP. Again, this is a customer response. And then we call the events and how much we get out of that is up to the customers. And we reduced that by another 20 megawatts. And based on some M&E studies we reduced our forecast for business and energy coalition by 10 megawatts.

So, in general, our very conservative forecast for '08 is around 826 megawatts. However, we have a lot of activities to boost that to higher levels. I would like to go through them a little bit.

One of them is -- we have activities, trying to firm the responses in several areas. One of them is trying to market automatic DR into the price responsive area so that, for example, given, in the demand bidding program. The customer may or may not respond, although they're in the program. They may or may not respond. But if you have automatic DR in the mix, typically they, upfront, accept the situation. And when there is a call they will respond.

So they're not in the loop unless they bid out. So although they're in the voluntary program, they may get their results from those customers. So, we have activities in that area to market automatic DR.

And then we have plans to improve business energy coalition programs which, based on M&E studies, have not performed as predicted in here. And we'll be working on those.

So, in general, we have areas where we're trying to improve the response this coming year.

And, again, from operating these programs, we'll take any questions you might have, but David Reed has gone over them, together with the other -- so I don't see any point in repeating some of those.

Thank you. If you have any questions?

PRESIDING MEMBER BYRON: Well, thank you, Mr. Sezgen. It would seem, in PG&E's case, our DR impact expectations are slightly higher than what they are showing us here today, correct?

MR. SEZGEN: That's correct.

PRESIDING MEMBER BYRON: By about 60 megawatts, 55 megawatts or so.

MR. HUNGERFORD: Right, and our numbers don't include the recent settlement that was made between PG&E and DRA and TURN on the expansion of their AC cycling program. That accounts for quite a few megawatts.

And their estimates for their peak pricing program, they backed down a little bit on what they're expecting for this summer. So, we can incorporate those, as well.

PRESIDING MEMBER BYRON: I can't help but notice that PG&E's number's a lot smaller than Southern California Edison's number. But we'll leave that for another workshop.

MR. HUNGERFORD: No comment.

MR. SEZGEN: Well, I think that would be your AC cycling program which was -- PG&E started last year. And we only had 5 megawatts this '07; and then we're ramping up.

PRESIDING MEMBER BYRON: Good.

MR. SEZGEN: And I'd like to add one

more point which is another activity we're working on is we have a new program before the California CPUC, which is what we call the cafeteria-style menu. And it's, I think, in the -- by the end of this month there'll be a decision as to it's a go or no.

The interesting feature of that program is the customer's given a lot of choices in that. And we believe the some reasons for customers not participating in that is their constraints are not represented in these programs well enough.

So we have this new program where the customer can pick the times they can participate, the days, the number of days, and the conditions. So we believe with that program we can sell much more demand response this coming summer. And it's going to be decided by, I think it's on the agenda on the 30th or I'm not exactly sure, but.

So, if that goes through we'll be able to boost, we believe we have a big push for selling programs in an integrated fashion with energy efficiency, that's another thing.

We try to sell energy efficiency first. And then later on demand response. That means typically we take a hit at demand response targets or responses we may get. However, in general, if you look at them together it's a better deal for the customers. And it's a better situation for the society in general.

So, again, we're trying to sell energy efficiency together with demand response. And we're trying to improve participation through incorporating customer choices in terms of when they can do what, and basically the idea is to be able to map the customer demand responsiveness as good as possible to the markets and get the most out of it.

PRESIDING MEMBER BYRON: Good. The notion of customer choice, I think, sounds very appealing. I hope it's more effective than the penalty process. Do you really call it cafeteria style?

MR. SEZGEN: Well, the name will change. I don't know how that name --

PRESIDING MEMBER BYRON: Okay. I mean, far be it from me, as an Energy Commissioner, to tell you how to market demand response programs these days. But I think people prefer gourmet food over cafeteria.

(Laughter.)

MR. SEZGEN: Right, right.

MR. HUNGERFORD: It was the comfort food movement initially, macaroni and -- comfort food with --

MR. SEZGEN: The name change is in the works.

PRESIDING MEMBER BYRON: Thank you.

MR. HUNGERFORD: Now, I believe that Ms. Smutny-Jones from the ISO has some comments on their perspective on demand response.

PRESIDING MEMBER BYRON: And before Ms. Jones goes, did you have a representative from San Diego?

MR. HUNGERFORD: Steve, do we have San Diego on the phone?

MR. FOSNAUGH: Is there someone on the phone from San Diego?

MR. HUNGERFORD: Apparently not.

PRESIDING MEMBER BYRON: No? Okay. Well, thank you, gentlemen, for being here today. I assume that we're going to come back at some point, though, to additional comments from the IOUs and SMUD with regard to our overall forecasts? We'll get some additional comments from them?

SPEAKERS: Yes.

MR. HUNGERFORD: Yes.

PRESIDING MEMBER BYRON: Apparently we do have someone from San Diego on the phone.

MR. HUNGERFORD: Tim Vonder.

PRESIDING MEMBER BYRON: Mr. Vonager?

MR. VONDER: V-o-n-d-e-r.

PRESIDING MEMBER BYRON: Mr. Vonder? Mr. Vonder, are you there?

MR. SPEAKER: The DR person --

PRESIDING MEMBER BYRON: Okay, we just heard "DR person". Please go ahead and introduce yourself.

MR. VONDER: No, I'm not the DR person.

PRESIDING MEMBER BYRON: Oh, okay.

MR. VONDER: That's Mark Ward, and I guess he's not available. And I don't know why. I wish I could comment on these, but I can't.

PRESIDING MEMBER BYRON: All right, well, thank you for being on the line. We'll go ahead then to Ms. Smutny-Jones, correct?

MR. HUNGERFORD: That's right. Did you have slides, Robin?

MS. SMUTNY-JONES: I do not.

MR. HUNGERFORD: Okay.

MS. SMUTNY-JONES: I'll be brief, a couple of remarks. I was asked to give a little bit of a preview and highlight of the ISO DR-365 demand response -- and I'll take the opportunity to do that. And a couple of comments surrounding that, brief comments.

And no discussion with ISO about demand response would be complete without our obligatory plea with regulators to discontinue counting demand response as resource adequacy products. I'm sure that my utility friends in the room will be shocked to hear this comment again, but we've been requested to speak until we're blue in the face about it, because we think it's important. I even have blue hair I've been talking about it so much.

First, I'd like to just mention briefly, the ISO is really excited about demand response. We really are dedicating a lot of resources to it, commitment. We're working collaboratively with the Energy Commission, the Public Utilities Commission to put together a comprehensive coordinated vision. We think it's going to play a tremendously important role in our new electricity world.

And a couple of key components of what we believe our vision is. We believe that's a shared vision. We're still working together on it. We want to help provide a leadership role in moving demand response into effectively a new paradigm. It's been viewed in the past as something we turn to at 4:00 in the afternoon on an August afternoon. Everybody needs to please go and turn down their thermostats and help us over the peak.

And we believe this is something that can be used effectively year-round, 365 days, thus the lab name, DR-365, to do all sorts of things to more efficiently use our resources. There's exciting ways to help integrate demand response with renewable portfolio goals. When windmills get to whatever it is, 50 knots, they shut down to protect the equipment.

If we can effectively tailor creative market-oriented demand response programs to come in and fill that gap, then we're taking the pressure off of more fossil fuel backups that would have to be there to help that facilitate the renewable integration.

Ultimately we believe with the right

economic signals customers can and will voluntarily follow those signals and react. And the technology is there, or it's around the corner. We've very excited about this, and real excited in working with you all to make it successful.

We've got some challenges in trying to figure out where the ISO wholesale electricity market integrates with the retail market and those programs. There's different roles and responsibilities.

There's aggregator roles; they might be regulated in one spot. There's the utilities that have their programs they're interested in. They're regulated somewhere else. The Energy Commission has new standards you're looking at to help advance some of these technologies. Commissioner Rosenfeld, god love him, is just dedicated, so dedicated to moving these things forward. So we're just real excited about it.

Let me make just a quick announcement about our DR-365 lab. Again, it's based on the notion that we should be able to count on demand response year-round.

Currently we have an area at the ISO,

it's meager, it's modest, it's on its way. It's evolving, it's not a very giant room, but it has some technologies, three residential-based, one focused on commercial customers.

And we're trying to expand demonstration and showcasing of these technologies. So when we have visitors, policymakers, groups, we have various tours; and people that come in, we can show them hands-on how this actually works. I don't want to take up a lot of your time today. I have a little cheat-sheet that kind of describes them in general and what they do. I'm happy to go through that with you if you'd like.

But, again, it's our way of saying we are committed and dedicated to helping with this. And our next steps will include showing how does it integrate with the market. What happens when, you know, the aggregator takes the information that we have at a wholesale price level and then translates that down to whether it's a utility or ESP or whatever retail customer would take that information and use it.

Now, for the blue-in-the-face comment. We've made this comment so many times, but the very simple concept is right now the emergency assistance utility programs, interruptible in particular, and I believe AC cycling included, are listed and counted as resource adequacy, as a resource we can count on.

The problem is we cannot access the interruptible programs, these emergency trigger programs, until we effectively at times violate our own reliability criteria by going into a stage 2. We can't get to it.

And I think one of the utility representatives mentioned today, these are summer programs. You'll have X-hundred megawatts, you know, in interruptible programs. And, by the way, they can only be used, called on a certain number of hours, and then they expire. You can't call on them anymore. And yet they're listed as being available year-round every month.

What you're effectively doing is taking, you're chipping away at the operational reserves and counting them in the overall planning reserve margin that you can, you know, should be able to access. You should be able to count on a RA resource.

I don't think this concept is lost on our friends at the Public Utilities Commission, and the utilities, and even the large customers. And there are some thorny issues to work out. But it's something we just need to keep mentioning because the overall consequence is we're acting under a reduced planning reserve margin. I think it's somewhere 3 to 5 percent of the actual margin would be these kind of programs that we can't get until we get into an emergency.

But to end on a positive note, we are talking, we are working, you know, with each other to try and work these out. But I just needed to once again make that plug.

And I think that's my remarks unless there are questions.

PRESIDING MEMBER BYRON: One would get the impression that you don't like these programs.

MS. SMUTNY-JONES: I don't think it's fair to say we -- well, obviously when we get into the emergencies we love these programs.

PRESIDING MEMBER BYRON: Yes.

MS. SMUTNY-JONES: Thank you for -- if you think that's coming across, we don't want it to come across that way. We'd like to see a transition to, again, a new paradigm where programs are economically based, and we send economic signals that tell customers to do different things.

And there may very well be an appropriate place in the future for these programs to remain. But, again, we don't believe they should count as our A resources.

PRESIDING MEMBER BYRON: Okay.

MS. SMUTNY-JONES: That's the point. And if I could just turn -- basically anything we should add?

That covers it. That's my remarks.

PRESIDING MEMBER BYRON: Thank you.

MS. SMUTNY-JONES: Thank you.

MR. HUNGERFORD: Thank you. And I have one more slide in the demand response section, and that's in the form of an announcement that the Commission has opened an order instituting investigation and rulemaking into to the development of load management standards under the Commission's load management standards authority.

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

And there will -- we are going to schedule a scoping workshop sometime in the near future, probably some time in mid-February, in which the issues that we'll be discussing in that proceeding will be scoped.

And so we invite anyone on the phone and anyone in this room and their organizations to attend. And to look on the CEC website for an announcement to that effect.

Thank you.

PRESIDING MEMBER BYRON: Good, thank you, David, for bringing that up.

MS. SMUTNY-JONES: May I add one more housekeeping announcement?

PRESIDING MEMBER BYRON: Of course.

MS. SMUTNY-JONES: I forgot to do this. I meant to lead with it, because I think folks who are here might be interested, if you haven't heard already.

The Governor today announced two new ISO Board Members, Laura Doll of Santa Monica. I think many of you know Laura was formerly directing the California Power Authority under David Freeman. And Mason Wilrich, who is current

Chair of the Board, was reappointed.

So those are two -- just a news flash I wanted to pass on.

PRESIDING MEMBER BYRON: Good, thank you. Two good choices.

MR. WOODWARD: Thank you. I'll be glad to present now the third of our three-D presentations on the demand forecast, demand response, and now dependable hydro capacity.

Good afternoon, Commissioner Byron, stakeholders, interested parties. I'm Jim Woodward with the electricity analysis office. And it's my pleasure today to present the statewide picture of dependable hydro capacity for this summer.

Because it's mid-January and still early in the 2008 water year, I won't be presenting any statistics about the current snow pack in the Sierra, or the amounts of energy that are generated from the volume of snow melt and forecast runoff.

Instead I'll stay focused on the capability of hydroelectric power plants to produce electricity during the peak hour of electricity demand this summer.

And if I'm very successful with this presentation, or if I fail miserably, this could be a one-time show.

First, a word about our sources and filings for the tables that are in the handout and posted to the web. The primary source of our filings for these numbers were the ten-year supply plans, resource supply plans, that were filed last year by the load-serving entities with peak load greater than 200 megawatts.

Plus we also, for the first time, had the year-ahead resource adequacy plans that the smaller LSEs provided to the Cal-ISO. And we also requested for the first time statements and tables, if we could get them, from the small publicly owned LSEs elsewhere in the state.

So those numbers are roughly a year old, but in some cases they're the -- like for the small POUs outside of Cal-ISO, those are the most recent numbers available on supplies, including hydroelectric capacity.

And we used those filings, the ten-year filings. We specifically looked at August 2008 for a consistent approach statewide. And for the year-ahead RA filing, we used 2007 because that's all we had, as a placeholder for what we expect in 2008.

And in our instructions to the LSEs, adopted a year ago by this Commission, for those ten-year supply plans, we specified that unless an LSE states otherwise, that a hydro resource must be able to operate during four super peak hours for three consecutive days for capacity in that month to come. And with very few exceptions that's the metric they used.

One exception was LADWP that said they count Castaic 1175 megawatts for one hour. Very reliably. They can get it for eight hours. After eight hours it's down to 1160. But the number for one hour is 1175 for Castaic.

A second standard, a little different than for utility-owned and utility-controlled, would be the QF, qualifying facility, hydro that is run-of-river. And according to the MRTU tariff, which reflects the resource adequacy conventions, it will be determined based on historic performance during the standard offer 1 peak hours of noon to 6:00 p.m., using a three-year rolling average. And that was meant to be comparable to how capacity is counted for wind.

So those are one-in-two conditions for QF.

And I thought that might be a concern until I looked at the numbers, themselves, and found that for QF hydro they're really -- the numbers are fairly small; 61 megawatts for PG&E, one for San Diego, 17 for Southern California Edison. So those numbers for QF hydro contracts are fairly small on a statewide basis.

The large bulk of hydro resources are utility owned and are large, over 30 megawatts. This number for PG&E, 4370 megawatts, includes just under 1000 megawatts under contract from their long-term partners in irrigation districts like Nevada, water agencies like Placer County.

And that's just a tradition that we've used for a long long time, although they're not specifically utility-owned and not necessarily subject to dispatch, in general, we've included that 1000 megawatts or so with PG&E's own utility-owned dispatch system.

The second largest hydro capacity resource is owned and operated by the Department of Water Resources for the State Water Project. And these are the numbers onpeak provided to us. They gave us a supply plan for the offpeak period, which is when most of their load occurs. But they're also available onpeak, and we thought that was the number that would be of more interest to Cal-ISO and others, since that's when the coincident peak occurs in Cal-ISO and statewide, it's onpeak.

And you see, most of that, again, is large hydro. DWR has a significant de-rate of 530 megawatts in a dry year, going from the median one- and two-year conditions. But I would also note that their pumping load also would go down in a dry year. There's less water to be pumped and delivered.

As they said to us, on an energy basis their worst case year is the median year, when there's water to be demanded, and there's water available to pump, and they're an energy consumer on net.

I'll come back up to this slide in the dry year de-rate for PG&E, one is graded confidentiality by our Executive Director in the IEPR filings for 2007, as it was in 2005.

And I will tell you that that number is not a big number, as can be inferred from publicly available information, some of which I'll present later. PG&E is here, as well, today; and may say something on that point. But it's not included in this total of 605 megawatts per Cal-ISO. And I can assure you it's not a big number.

For Southern California Edison, this includes their share of Hoover; it includes their Big Creek hydro system; and their smaller hydro resources, a few in southern California and on the east side of the Sierra, like Bishop Creek.

And notice, too, there's no dry year de-rate. I think that's largely a reflection of the system's infrastructure, which we'll illustrate a little bit. And also reflects the dependable hydro capacity numbers really are based, in many cases, on the one-in-five or dry-year assumptions.

So, CCSF stands for the City and County of San Francisco Hetch Hetchy power system. And most of that is for their own self-provided load in the city, though they do have a little bit of retail load at San Francisco Airport, elsewhere, Treasure Island. But largely that's self provided.

Silicon Valley Power has shares of the Collierville Plant with NCPA; got the Grizzly Plant on the Feather; and also some small hydro on the west side of the Sacramento Valley.

NCPA's resource is largely the Collierville Plant, and that's for the members of the power pool. And then there are 12 other load-serving entities in Cal-ISO that have hydro, utility-owned or under contract. And that would include Pasadena, Riverside. San Diego Gas and Electric has 1 megawatt. Azusa has 20 megawatts from Hoover and 20 under contract from DWR Diablo Canyon. Vernon has 22. Power and Water Resources Pooling Authority has about 22 megawatts.

And these numbers, let me go back. How do I go back here, Denny?

(Pause.)

MR. WOODWARD: Okay. This number I want to call attention to in the bottom right corner, the sum for Cal-ISO, the balancing authority area, is 7594 megawatts. It should be compared to this number that was in Denny's presentation, slide 13 I think, earlier, and that's the de-rated hydro based on a deterministic approach.

And using a different set of filings, different sources of information are supplied in the resource adequacy filings, you can see that this deterministic number is very conservative compared to what we'd expect, what the LSEs can count on through resource adequacy.

And those are the conventions that were adopted as standards established by our sister agency, the California Public Utilities Commission, and which have been adopted by the FERC-approved ISO tariff.

And there are a couple other caveats about hydro capacity for LSEs within the ISO. For qualifying capacity, as we said, it's based on the dry year, which, by definition, could occur one year in five, any given year.

It's not looking at carryover or multiple dry years in sequence, but it's based on taking the statistics that are available and using the -- variable head de-rate, and it would be the one-in-five-year such as the fourth driest year in the last 20 years on record for that month. It's not usually the same for all months of the year.

And also Cal-ISO retains some discretion over the hydro capacity resources owned and controlled by LSEs, those noted on the bottom bullet point. That influence is offset by this general exclusion that pumping load and -- participating load and generation units of hydro are not subject to the residual unit commitment process, because they're use-limited resources, energy limited.

They're not available -- they're not required to be available to the ISO and in the day-ahead markets and real-time markets if they're not scheduled for use by that LSE. And that's a reasonable accommodation for this type of renewable resource. That you can only run the water through the turbines once unless it's a pump storage unit.

So, Cal-ISO can discuss annual use plans, suggest revisions to the reliability -- or the reliability needs of the system. We don't know how that's going to develop under MRTU, but we'd be glad to learn more about that from the ISO Staff, as those resource use plans are developed and modified. I think that's a placeholder allowing for continued discussion and dialogue, if there is any residual concern.

Now let's look at the other balancing authority areas here in California. I'd better back up and say one other thing about this chart. Now I'm lost -- I'll stick with this one.

Hydroelectric capacity is a significant

resource for all six publicly owned LSEs in the SMUD western balancing authority area. Note that SMUD does not de-rate their hydro generating capacity, which is warranted, I believe, as I'll explain later.

This table does have one minor error in the column for contracts that are backed by hydro. The number shown is 438 megawatts, which was their year-ago estimate for July of 2008. What I should have shown here, but did not correct, would be 414 megawatts, SMUD's forecast for August 2008.

And as I mentioned for statewide consistency, I tried to use August 2008 numbers because that's when hydro would be less statewide than it would be in July. Although it's not always.

And we include Western here as end-use loads. That's an estimate, 137 megawatts. Western was not listed in Cal-ISO again for consistency with the supply and demand tables. Although they have end-use loads and total requirements, customers like Trinity PV, that are backed by hydro supply.

They're already counted as an import to the ISO on that table that Denny had earlier. So, to avoid double-counting we don't list Western's end-use loads which would be about 367 megawatts for their scheduling controller ID numbers. Western's end-use loads within the ISO, about 367.

So, moving on to the Los Angeles Department of Water and Power balancing authority area. This is a very straightforward simple table. And what you see is that Burbank and Glendale each have 20 megawatt shares from Hoover. And LADWP has much more that comes from Hoover, over 490 megawatts when Hoover is full; plus two aqueducts coming from the Owens Valley, and the Castaic resource on the west branch of the California Aqueduct.

And they don't do a de-rate of those numbers. We asked and they said no, that's what we count on.

So on a statewide basis, this is a summary of those three previous slides, plus we've added now Imperial Irrigation District, 33 megawatts over 30 -- a total of 65 megawatts for Imperial Irrigation District. And that's all run-of-canal hydro on the All American Canal.

And Turlock Irrigation District, 146 megawatts. Most of that's New Don Pedro. And they will offer a de-rate for a dry year. Gave us a number there. Turlock's in its own balancing authority area with Merced Irrigation District. And this number on their contract includes 3 megawatts that is provided to Merced Irrigation District from Western.

Interestingly, Turlock and Modesto are a little more sophisticated than most LSEs in forecasting hydro capacity, and more importantly, energy for them. They used actual reservoir levels plus actual snow pack conditions, plus the one-in-two forecast of continued precipitation as the season goes on. Being an irrigation district with power supply and customers, they can do that.

We were curious how would a severe drought affect hydro capacity. That was in the workshop notice. So, taking the filings from the 2005 IEPR, we looked at where de-rates, additional de-rates would be noted.

In 2005 we asked for capacity in a one-in-ten critically dry year. Now, you'd get better than that in nine years out of ten. And these were the four entities of LSEs over 200 megawatts that replied with additional de-rates going from a one-in-five to a one-in-ten. And that's only 140 megawatts.

And I've added this number here that was not in the handout that was posted. I looked just yesterday at Western's forecast for the Central Valley Project. It's posted on their web as of December 21st for the month of August 2008. They do a one-in-two forecast and a one-in-ten forecast. And the net reduction, going from one-in-two to a one-in-ten for Western's Central Valley Project is only 175 megawatts.

Their capacity from Western's plants like Shasta, Folsom, New Melones would go down by 252 megawatts, but they also have reduced pumping load on the Bureau of Rec project loads by 70 megawatts.

So the net, if they have a one-in-ten from this point forward would only be 175 megawatts for Western --

PRESIDING MEMBER BYRON: So is that the de-rate or the capacity?

MR. WOODWARD: That would be a de-rate. The total capacity of Western's system is about 1250 megawatts.

So the larger point I would offer here is that hydro capacity does not de-rate in proportion to the annual or monthly snow pack or runoff. It's the energy that will follow that much more proportionately.

We have found, and the loads and resources studies back this up, that utility-owned hydro capacity, by and large, uses high head and stock infrastructure. These are low volume, high head facilities that are not subject to the gross head de-rates that are caused by low reservoirs.

And they do very well at managing to keep those reservoirs full through the summer when the power is needed most and when it has the greatest value.

The ones that we see better here in Sacramento, the ones that are more conscious in our minds are the multiple purpose reservoirs, water storage, inner basin, transfers, flood control, reservoirs like Shasta, Folsom, New Melones and others like that.

But I would say those capacity and energy numbers, looking ahead, are very transparent, especially by Western, both in the mid-Pacific office here in Folsom, and the lower Colorado office in Boulder City, do publish at least 12 months for the Central Valley and 24-

month-ahead forecast of reservoir levels, water flows, capacity and energy. So it's not a secret from our participants on what's coming there.

And to illustrate, the infrastructure really has a dependable capacity. I've added some kinds of slides. This is the Moccasin Power House built by the City and County of San Francisco to generate power from their Hetch Hetchy project. It's 118 megawatt capacity does not diminish when the Hetch Hetchy Reservoir is drawn down.

The three major power houses, Moccasin, Kirkwood and Home are all located miles west of Yosemite National Park, and are all supplied by water diverted from the Tuolumne River.

Local size of California hydro plants may vary tremendously. The majority of utility bill megawatts use an infrastructure that is high head, low volume; saying low volume compared to the Columbia River. And these have the ability to dispatch the plant to follow loads.

The catch in here describes the Hat Creek number 2 power house, and you can see the penstock delivering water to the plant with a drop, a gross head drop of some 700 feet from the supply lake. And this is not a run-of-river hydro; it's not dependent on a dam located in a river.

I took this photograph in October 1980 showing a PG&E canal in Mokelumne Canyon built in 1931. The Canal is running full on a warm, full day, delivering 750 cubic feet per second to 37 megawatt Tiger Creek. When that water is discharged, diverted again and delivered to 98 megawatt electric powerhouse.

The PG&E system has 68 powerhouses, 99 reservoirs, 184 miles of canals, 44 miles of flumes, 135 miles of tunnels and 19 miles of pipe, mostly penstock. Those were expensive to build decades ago, and it's remarkably dependable today.

Here we see a portion of Edison's Big Creek Project on the upper San Joaquin River. Note the 1500 foot drop from Huntington Lake to Shaver Lake. Well, if Huntington Lake goes down by 20 feet or 50 feet, it doesn't change the gross head significantly, which is what's related to capacity.

The Portal Powerhouse, it discharges into Huntington Lake, is fed by Lake Thomas Alva Edison nearly 700 feet higher. In between Huntington Lake and Shaver Lake is the 207 megawatt Eastwood Pump Storage Plant that can pump water back to Huntington Lake.

There are four more powerhouses that you see here that produce energy from water as it drops back down to the San Joaquin River Canyon. And there are two more large powerhouses outside farther downriver.

I took this photo of Union Valley Reservoir, SMUD's largest storage facility; and the Crystal Range in June of 1971 here. And the Union Valley Powerhouse there at 46 megawatts was certainly able to generate full capacity.

But this powerhouse was probably derated significantly or offline after the two driest years in recorded history in northern California. I took this photo in August 1977 on a hot weekday. I was working for the U.S. Forest Service then, the El Dorado.

And there's something else notable in this photo, not readily apparent. The pipe here in the foreground is a penstock that delivers water to a dependable 24 megawatt Robb's Peak Powerhouse, which discharges into Union Valley Reservoir.

The gross head down from Ice House

Reservoir is 356 feet. And you can see, if you look close, the riffles of white water as it runs down the exposed lake bed. Which means the power was being generated at Robb's Peak Powerhouse here that day.

And also farther downstream, below Union Valley, at 154 megawatt Jaybird, at 157 megawatt Camino, and again at 230 megawatt White Rock, each of which are fed by penstocks in SMUD's system. A golden staircase it's sometimes called.

In 2003 we asked many hydro owners, especially utilities, but all large hydro owners throughout the state for information on their hydroelectric facilities, environmental data, operational data, historic generation data.

And in 2003 SMUD stated to us the basis for their dependable capacity determination was, quote, to provide sustainable capacity during a repeat of 1977 hydro conditions." And at that time even Union Valley is expected to produce 40 megawatts if 1977 conditions were to repeat.

I don't think you'd ever seen Union Valley Reservoir drawn down this far again in August, especially with the conditions of the recently licensed Upper American River Project.

Mr. Luskin's nodding his head affirmatively. So this is a unique photo.

When it's absolutely full Folsom Dam can generate 199 megawatts with the rated gross head of 300 feet. Here it's shown spilling water in February of 1983 during the wettest year on record. For this year in August, Western expects Folsom capacity to be at 192 megawatts under medium one-in-two conditions. And if it turns out to be one-in-ten critically dry year, it'd be 153 megawatts.

But it won't be zero megawatts like it probably was in August of 1990 when I took this photo. This was year four of a six-year drought that began in 1987, and continued through 1992. The entire lakebed here, from Folsom Dam to Beale's Point, is exposed.

Summer 1990 was an extremely hot year. According to an October 1990 report by Mary Ann Miller in our office, quote, "all three large seven utilities set a new all-time record for electricity demand on June 27th." This is 1990. PG&E and SMUD set new all-time demand records in August of that year.

In 1990 PG&E customers collectively beat the previous annual peak demand record six times. SMUD customers did it five times. LADWP customers five times. SDG&E customers 11 times. And Edison's peak demand beat prior year peak records 11 times in 1990.

And yet there is no summary, no hint in the summary of loads and resources from 1990 that I could find any mention or concern about hydro capacity. Nor were any units over 200 megawatts reported offline during that summer.

Remember please that most of the water used to generate electricity during the summer is not stored in manmade reservoirs, lakes or underground springs. For every summer the biggest storehouse of water is the Sierra snow pack shown here in May of 1982, a wet year. This is north of the Upper San Joaquin River.

Still, some will worry about the available supplies because a shortage of water due to drought is inevitable in California.

The worst two-year drought in recorded history was 1976 and '77. And yet there was still more than adequate hydroelectric supplies. I meant to mention in that year PG&E, in 1977, based again on loads and resources reports that we had on file, in 1977 at the time of annual peak PG&E reported in their summary of loads and resources, to the Energy Commission in response to a Commission order, that hydro capability at the time of peak was 5281 megawatts, not including pump storage. Helms (phonetic) was built later. And that 5281 in 1977 that PG&E reported did include Western's capacity of 1250 megawatts as I mentioned earlier -- remarkable performance based on records that we have.

Well, this is a view -- I took this picture in November 1990 in the area just north of Mt. Whitney. The annual snow pack is completely gone. This was after four consecutive, critically dry years in the San Joaquin Valley, starting in 1986. And it continued for two more years after that.

This was the worst six-year drought going back to AD 901. And this is based on reconstructed river system runoff by the Tree Ring Lab at the University of Arizona Tucson. In a 2001 report DWR, they found fossil tree ring while excavating the foundations for Oroville Dam in the 1960s.

So there was no six-year period that was dryer than 1986 to 1992 dating back to 901 AD, which makes this a one-in-1100 years event. Ending the water year in September 30th would be cause for concern if we ever had a winter without any snow. it appears that has never been the case since 901 AD.

Though two years of 1579 and 1580 were significantly dryer than 1976 and '77. There may have only been one or two winter storms in the year that Sir Francis Drake stayed on the coast with all its stinking fogs.

Be that as it may, as soon as the first winter storm has arrived, the first hydropower fuel has been downloaded for the following summer. And in carryover worries about huge de-rates in hydropower capacity for the next summer are unwarranted.

By the way, this is the southern high Sierra in May of 1982, and that's Mt. Whitney at the far left, looking east.

Think of your car for a moment. When you're running low on gas it doesn't reduce how fast you can go. It only reduces how long you can operate at a given speed. If you can get that fuel to the cylinders, you can drive a car as fast as it was designed to run.

The hydro system operators know how to get the fuel to the turbines and at the time it's most needed to serve their customers. The hydro system operators have decades of experience and knowledge of how their systems perform. The resource adequacy counting conventions for hydro capacity are well accepted. They're not controversial among the Commissions and the LSEs. They are using them.

When it starts to swelter here in the valleys, this is a resource that can be counted on dependably year-in and year-out. And until then, at least for the snow pack, I hope we can just chill.

Thank you.

PRESIDING MEMBER BYRON: Thank you, Mr. Woodward, a presentation unlike any I've heard at the Commission before.

(Laughter.)

PRESIDING MEMBER BYRON: And good graphics, too. So, bottomline, if I'm to take your last slide, the numbers on it, adding 140 and 175, about a 300 megawatt de-rate in a one-in-ten dry year, correct? Notwithstanding all the other points you made with your photographs.

MR. WOODWARD: Illustrated.

PRESIDING MEMBER BYRON: Thank you very much.

MR. WOODWARD: Thank you, sir.

PRESIDING MEMBER BYRON: Any questions for Mr. Woodward? Good.

MR. WOODWARD: I was asked to try and provide some operating or performance or hourly data for the resource adequacy conventions and assumptions that we've used. And they seemed plausible. They seem to have veracity and utility.

PRESIDING MEMBER BYRON: Nevertheless, you have data that goes back to 1201. That's better than --

(Laughter.)

PRESIDING MEMBER BYRON: That's better than other groups in the Commission.

(Laughter.)

MR. LAWSON: Gary Lawson, again. I don't know if it's necessary to throw up the slide. In talking with Jim earlier this week I think he just was looking for some confirmation of his findings, at least as regards SMUD's own U--

system. And Jim is correct.

In regards his awful-looking slide of Union Valley Reservoir from the '76-77 drought, we were under an integration contraction operation with PG&E at that time, and so our resources are operated completely different now, as a control area.

So we would never let that reservoir get that low because we operate all our reservoirs to maintain our dependable capacity, particularly in the peak season of the summer months.

I just wanted to reiterate that for you, and to support staff's conclusions.

PRESIDING MEMBER BYRON: So you are confirming their conclusions? And also blaming PG&E for drying the reservoir up?

MR. LAWSON: Yeah.

(Laughter.)

PRESIDING MEMBER BYRON: Thank you.

MR. WOODWARD: Is there some rebuttal from PG&E or --

(Laughter.)

PRESIDING MEMBER BYRON: That's not necessary.

MR. WOODWARD: Okay. Most of us have an

alibi for that period of time, 1977.

MR. TOM: Good afternoon; my name's Bill Tom, I'm with PG&E. I'm the Manager of Electric Supply.

And, Jim, you're a hard act to follow. You very eloquently discussed the hydro situation, the capability of the northern California hydro system, in general.

I would like to elaborate a little bit on what you've said, primarily focusing on slide 10, where you mentioned that hydro capacity is not de-rated in relation to the changes in the precipitation and snow pack.

And we agree with Jim's conclusion that for the PG&E hydro system the capacities for our system during wet, dry or average years do not change very significantly.

One thing that does change during dry years is the energy production. What we would do is attempt to focus and generate during the high-value, high-load months, load hours. And what would be reduced would be the energy production during the offpeak and shoulder hours.

So we again support Jim's conclusion that energy production would be the key parameter that would be affected by a drought.

One of the reasons, or the major reason why we can conclude that the capacity of the plants don't change significantly during water conditions is that our reservoirs are not the large, variable head plant facilities that the state and the federal government have. Those are multiple-use reservoirs, primarily built to store water for irrigation, navigation and recreation.

We at PG&E employ a planning process that is two years, an ongoing two-year planning horizon which at the end of the first year we assure that the reservoir storage levels are adequate to, I guess, generate peak power during a following year, assuming that it could be dry. So we have a two-year hydro planning cycle within our own organization.

Most of our facilities are like Jim was saying, we have forebays in front of our power plants, so that basically they store enough water for peaking operation. And then shut off for storage for the next day's peak or the next week's peak. So it's basically unlike the Central Valley Project or the DWR facilities. We operate primarily focusing on peak operations.

I do want to clarify one point that Jim made initially where he mentioned that as part of the hydro dependable capacity there was 1000 megawatts of irrigation district facilities that we do have under contract.

We do consider those facilities at our disposal, subject to the terms of the contracts. Within the terms of the contract usually the irrigation district or the water agency has water requirements which basically say they have primary discretion on the use of the water to meet their own requirements, their own irrigation requirements, their own FERC Regulatory Commission operating requirements.

Then after all those requirements are met, then we have the discretion to actually dispatch and schedule the generation from those facilities to meet our loads. So that's under the terms of the contract, is how we operate and integrate those facilities into our hydro portfolio.

Finally, I would like to say that right now I agree with Jim, it's too premature to reasonably predict the generation that we would expect from the hydro system. But I would like to say that due to the latest storms we've had about 10 inches of precipitation. And from our preliminary assessment the snow pack, as of today, is about average for this time of year. So we're keeping our fingers crossed that, you know, hopefully this will be a reasonably good hydro year.

And we expect a rebuttal on the SMUD arrangement under the integration contract.

(Laughter.)

MR. TOM: I believe we have, you know, requirements under that contract, too, so that, you know, restrictions on our use. So that's my understanding. Typically, you know, I wouldn't think that we would be allowed to enter into a contract that give us free-for-all on somebody's system. So it's pretty much, in my recollection, similar to what we have with respect to our irrigation contracts. There's some parameters that we have to be operating within.

So, that concludes my presentation.

PRESIDING MEMBER BYRON: Very good, thank you, Mr. Tom.

MR. WOODWARD: Thank you, Mr. Tom, and from what I've heard from others, that would be true of other utilities also, that Edison, for example, would not be drawing down their Florence Lake and Thomas Alva Edison Lakes like they were in 1977, to nearly zero pool or minimum pool.

So, there is more focus on carryover storage to allow for a safety factor for those seven consecutive dry year, if it's critically dry.

Are there any other comments on the presentation, corrections? I'm always willing to learn more online or offline about the systems.

If not, I'll turn it back over to our leader here, Denny Brown.

PRESIDING MEMBER BYRON: Thank you, Mr. Woodward. Mr. Brown, I understand that we have someone from San Diego Gas and Electric that's on the line, holding to speak on our previous item 4. So maybe this would be a good time to go back to our demand response and interruptible load programs and hear from San Diego Gas and Electric.

MS. VESA: Thank you. This is Athena Vesa with San Diego Gas and Electric. And I apologize for being late at the meeting.

PRESIDING MEMBER BYRON: No, no problems, Ms. Vesa. Thank you, we're glad to have you. Go right ahead.

MS. VESA: Also I do have a presentation that I'm looking at. Unfortunately, we didn't get done on time to share with all of you.

But what we wanted to go through in the small amount of time that we were able to converse with David Hungerford to find out what information would be useful for the purpose of this meeting, we are talking about our internal procedures, when we determine where economy of DRs end. Is that useful to you?

And so during the summer seeing this particularly we have what we currently call day-ahead programs or should be more closely aligned with price response programs. And we have day-off programs which typically are more than reliability type programs.

So, at the beginning of every day in the summer we meet with our electric and gas procurement staff to discuss the status of the relevance to determine if any of the DR programs will need to be called.

And our procurement staff actually makes the decision. And it's primarily based on price. And in particular, the currently trigger a program, 3 DR programs that way. It would be our summer saver program, which is our AC cycling program; our capacity bidding program, which is a statewide program; and our clean gen program, not quite a demand response program per the definition of the PUC, but it's a backup generation type program.

So, these programs are triggered to meet bundled load requirements on an economic basis, determine a minimum load threshold for triggering each program. And it depends on the availability of hours and how many times we've already called them during the season.

And so once the threshold is reached, our procurement people will compare the costs of any of these demand response programs to the current other resources that they have, including their market purchases. And that's what determines when a demand response program will be triggered.

And additionally, if any of the DR programs are under-utilized throughout the summer months they may reduce the load threshold for triggering the program.

Regardless of remaining hours each

program triggered by the procurement group only if it's economic compared to other resources that they currently have.

The procurement group will also trigger demand response programs to support any system reliability concern that's directed by grid operations and emergency operation center or the ISO. And as such, SDG&E reserves a certain number of hours in availability for each of these programs for emergency conditions.

So, in general, what we have in terms of how we call our programs that are price-responsive.

Then we have what we call our soft triggers, which are weather-based or both based -- on the system load at the moment, and we can call our other demand response programs based on that.

And so for day-ahead programs we make these types of decisions the day before we're going to call the programs, and we inform all our customers after 2:00 in the afternoon to let them know that we are going to call the programs tomorrow. And for the day-ahead programs, we work with our grid ops people and our procurement people and we are notifying customers as soon as possible. Because I think we can call up to 30 minutes ahead of the event.

And so in general those are SDG&E's over-arching procedures for calling demand response programs. And we'd be happy to answer questions on that, if there are any, the best that we can.

PRESIDING MEMBER BYRON: Ms. Vesa, thank you for joining us. I guess the primary question I have, it would be can you put some numbers to it? Our staff has indicated an expectation of about 107 megawatts for the San Diego Gas and Electric service territory. Can you provide us a number or corroborate that one?

MS. VESA: If you can just hold on for a few minutes.

PRESIDING MEMBER BYRON: Certainly. And while you're looking that up, Mr. Brown, where are we headed from here, after we close on this particular topic? Are we going to hear from the IOUs with regard to the forecast in general?

MR. BROWN: That's correct.

PRESIDING MEMBER BYRON: Okay, thank you.

MR. BROWN: We'll open up to any general

comments.

PRESIDING MEMBER BYRON: I don't hear an adding machine going in the background.

(Laughter.)

(Pause.)

MR. HUNGERFORD: Well, I think San Diego could provide comments by -- they could send a letter or an email to us and we could forward it to the Commissioners, the Committee, to provide that input to you, if necessary.

Would that be acceptable, Commissioner?

PRESIDING MEMBER BYRON: Sure. Really what I'm interested in is you getting the feedback and having the opportunity to resolve these things. And we could do it by letter, but if Ms. Vesa's still there it's always nice to press them a little bit, to put them on the spot here, too.

(Laughter.)

PRESIDING MEMBER BYRON: Ms. Vesa, are we going to get an answer?

MR. HUNGERFORD: Well, this is partially my fault. I had spoken with your Advisors who had asked me to ask the utilities to provide some information about the way in which they went about triggering their programs for the summer.

PRESIDING MEMBER BYRON: Ms. Vesa, it looks like you may be off the hook here for now.

MS. VESA: Okay, but I think in going over some of our results and our numbers, we can substantiate that number. We can come close to it.

PRESIDING MEMBER BYRON: Okay. Again, thank you for joining us. And if it was late notice, we all apologize. And we appreciate everybody being here on such short notice, I should say.

Anything else, Ms. Vesa?

MS. VESA: No, not if you don't have any more questions.

PRESIDING MEMBER BYRON: Okay, thank you very much. So we'll go ahead and finish up with our agenda, then.

MS. VESA: Thanks for giving me this opportunity.

PRESIDING MEMBER BYRON: Thank you. Mr. Brown.

MR. BROWN: At this time I believe we had Southern California Edison wanted to make some general comments on the supply outlook. If you'd like to go ahead.

MR. ALVAREZ: Good afternoon, Commissioner. Manuel Alvarez, Southern California Edison. I think you heard a lot of our issues, and I just kind of wanted to bring it up to a summary level.

Fundamentally, while we have some differences of assumptions, our overall conclusions with the Commission's analysis is pretty much the same. So we feel comfortable with you folks going forward with the findings and information that you have.

You heard earlier about some questions on methodology on the peak demand area. I think those are going to be with us as we proceed into the IEPR for the next cycle, and looking for such solutions is probably paramount on our agenda.

There was an issue that showed up on the Inland Empire project. We only count half of that project as part of capacity, so that's actually one of the main differences that just needs to be accounted for.

And then our hydro assumptions we pretty much agree with the staff's assumptions, so we have no concerns there.

And then the last thing, you heard a

lengthy discussion on the DR issues. And I just want to ask Dave if he has another issues he'd like to bring up before we close out our concern. Dave?

PRESIDING MEMBER BYRON: Thank you, Mr. Alvarez. The Inland Empire Plant capacity ratings are the important point. Appreciate that very much.

MR. ALVAREZ: Thank you. And I guess I'd like to add one more comment with regard to the dry hydro assumptions, which seems, after Mr. Woodward's presentation, that we're -- how can I say this -- the utilities have been running these plants for decades very effectively.

And I was talking to Yakout Mansour yesterday with regard to our workshop, some of the assumptions that we're making, as well. And he's concerned about a potentially dry hydro year, as he is every year. But that's the nature --

MR. ALVAREZ: He has a lot of issues to be concerned with.

PRESIDING MEMBER BYRON: That's correct, that's the nature of his job.

MR. ALVAREZ: On a daily basis.

PRESIDING MEMBER BYRON: And I guess I'd

just like to point out one thing, you know, when the unexpected happens, as it did July 24th or so in 2006 when we get a one-in-ten or a one-in-58 kind of temperature event, the ISO is actually the one that came forward and found all those additional resources that kept us in business during that period, too.

But I'm still getting the distinct message that the hydro, even in dry years, is still good.

MR. ALVAREZ: I think actually your point is well taken. I'd like to just put in a plug for another activity the Commission's involved with, and that's the contingency planning exercises that it historically has always done. And many of the emergencies and concerns that we will deal with the energy system as a whole fall under that program.

So, perhaps revisiting some of your emergency standards and emergency contingencies is something to think about on your agenda in the future here.

PRESIDING MEMBER BYRON: Okay.

MR. SEZGEN: If I can --

PRESIDING MEMBER BYRON: Mr. Sezgen.

MR. REED: David Reed, Edison, again.

PRESIDING MEMBER BYRON: Oh, I'm sorry, Mr. Reed.

MR. REED: I just wanted to make an observation about the ISO's RA issue. I'm not a planning person, I'm not a resource adequacy expert, but I think there's a couple of issues there, or just kind of observations.

One, I don't think you can just assume that there's 600 megawatts of air conditioners cycling that we can transform into a price response program that the ISO can use. Because, in fact, if we call our cycling programs 20 times a summer, like we do with the price response programs, we have a lot of customers leave the program.

So the only amount that would be counted for RA, I think, for the ISO would be a much lower number. And we'd lose the interruptible component.

So we're really sensitive, although I think we do want to somehow come to a resolution on it, we're really sensitive to the balance between what we do to customers to get them to participate, and what we need to do for our system. So we have to kind of balance that out. We can't go, you know, we can't push customers too far or they'll start to get off the program.

The other thing is there's really kind of a paradigm shift that's just right down the road that I think will alleviate the RA issue for the ISO. In five years we're going to have 4 million customers, residential customers, on the price response program. Those same air conditioner cycling customers are going to be on price response.

So when we call a peak time of rebate event we're going to offer those megawatts for those same customers for the ISO for the day-ahead market. And then we need to fashion how we'll retain the interruptible capability of those same customers so that if we have an emergency we can utilize them for an emergency.

So I think the ISO would have what it wants at that point. You're shaking your head. So RA becomes almost a moot issue. And I think there's two things going on there to drive that. One's the MRTU and the other is the smart metering.

So, that's all.

PRESIDING MEMBER BYRON: Okay, very good. Thank you.

MR. HATTON: Hello. My name is Curt Hatton; I'm here from PG&E today. I'd like to thank the Commission for the opportunity to speak on the summer 2008 supply and demand outlook.

First I would like to commend the CEC Staff for continuing to employ a probablistic look at supply and demand issues, and resulting effects on reliability.

PG&E's analysis of the loads and resources in the California ISO, northern California region, indicate an adequate planning reserve margin for 2008 under average conditions, and assuming that imports do not decrease from last year.

PG&E does plan to fulfill its CPUC resource adequacy requirements to meet at least 115 percent of its coincidental peak demands for the month of 2008, and as well as have sufficient energy capacity to maintain at least a 7 percent operating reserve margin for an average summer.

However, we are concerned that the 0.7 percent probability of involuntary curtailment presented by the staff today under-estimates the probability of those involuntary curtailments.

One reason is, and I think Lynn spoke earlier of this, is that the staff does not include the effects of global climate change in its load forecasts. PG&E has previously presented information that the load forecast should include the potential effects of global climate changes. And given that global climate change is real, PG&E believes that the true probability of temperatures from the high end of the historic range being observed in 2008 are higher than the probabilities for that same event calculated from historic data.

Another reason is that the staff's methodology for calculating outage probability does not appear to include a nontemperature-related variance in load. We note from prior interactions with the staff that there's a significant nontemperature forecast error.

For example, in the 2006 load forecast report the 2008 peak demand for NP-26 was projected to be 20,827 megawatts. While in the most recent 2008 to 2018 report that projected NP-26 peak was 21,671 megawatts.

This is a 744 megawatt increase from one forecast to the next. PG&E believes that there should be some factor for nontemperature-related forecast error in the probability analysis.

Another reason is when one assumes stage 3 events are called in the analysis that Denny showed, he included a 1.5 percent operating reserve level for that. PG&E believes that 3 percent may be more appropriate level for determining when state 3 events could be called and the potential loss of involuntary curtailment.

ASSOCIATE MEMBER GEESMAN: Is that new? Because that 1.5 percent number has been around for a number of years now.

MR. HATTON: Well, I think it, again, for example, here a stage 3 notice is declared by the ISO any time it is clear that the spinning reserve portion of operating reserves is less than the ISO single largest resource or when real-time operations the operating reserve is forecast to be less than the single largest contingency.

I think there's some discretion as far as what one considers to be the single largest contingency and what percentage of the load that is. So I don't think it's a hard and dry 1.5 percent. I think that it's --

PRESIDING MEMBER BYRON: But is this a

new position on PG&E's --

MR. HATTON: No, no, I don't -- no, this is a position that we've held before, and we continue to have that.

We'd also like to continue to work with staff. We've had some good interactions with staff, and we'd like to continue to work with them to better understand a couple of items.

One would be totally resolve slight differences between the existing generation between what the CEC has and what the California ISO has. It would be helpful to sort of settle on a single number that would be consistent from agency to agency.

In addition, I think this was brought up earlier, too, from the ISO as well as from the CEC, that one important contributor to supply and demand balances, the amount of interchanges that one assumes.

So we'd like to continue to work with staff to look at the interplay between NP-26 and the surrounding control areas, and make sure that they're properly considered.

In the CEC's presentation I believe they indicated an assumption of 950 megawatts made for

WAPA imports to the ISO. It would be helpful to understand sort of the basis of this assumption. And it would also be helpful on a larger scale to look at all the non-California ISO loads and resources, and look how the interchanges between the California ISO, particularly the NP-26 area and the surrounding control areas.

Lastly, again this gets back to the probability assumption. We would like to work with the CEC Staff to better understand the probability assumptions in terms of mean and variance and probability distributions that they have used to represent some of the key uncertainties. I think you used demand generation outages and transmission forced outages.

So I think it would help facilitate our understanding, and perhaps we could contribute some information, as well.

PRESIDING MEMBER BYRON: Okay, good. Well, certainly by being here you're participating; that's the beginning of participation. I want to see all the investor-owned utilities intimately involved in our activities and our forecasting.

Do you have any more that you want to

add --

MR. HATTON: No.

PRESIDING MEMBER BYRON: Do you want to respond to any of those comments at all?

MR. BROWN: As far as doing supply/ demand balances for the individual balancing authorities outside of the ISO, it's difficult to -- in some of the balancing authorities it's difficult to get without getting into some sensitive numbers, when you go individually, utility by utility.

If we break it down by SMUD control area, Turlock, Modesto, and bring those in --

MR. HATTON: Well, haven't completely thought through it, but it might be able to have even from an aggregated sense of view, not necessarily looking at SMUD independently or WAPA or, you know, Modesto.

But look at them in aggregate so then therefore some of the confidential sensitivities may not be as apparent, but would shed some light, perhaps, on the interchange between the ISO and those neighboring control areas.

As I said, at the end, what we're not looking forward is specific interchanges between the ISO and one particular control area, but it's an aggregate, the imports and exports either to or from the ISO control area that we're interested, and the effects on the liability.

MR. BROWN: Yeah, I agree that would be very useful to have the interaction, as well as some parties from the other balancing authorities.

As far as the rest of the interchange, I'd be interested on PG&E's suggestion on how to handle the 3000 megawatt north-to-south assumption.

MR. HATTON: Yeah, that'd be good to also investigate, as well.

PRESIDING MEMBER BYRON: All right, thank you.

Ms. Marshall.

MS. MARSHALL: Yeah, on your suggestion about incorporating nonweather-related forecast error, we agree that's something we do. We'd actually started that process and we compiled some historic data. It's a work in progress, but hopefully in some future vintage of the outlook that'll be incorporated in the probability assessment.

MR. HATTON: Thank you.

PRESIDING MEMBER BYRON: Okay, thank you.

MR. BROWN: Is there anybody else with any comments on any topic at this time?

MR. BURT: I'm Bob Burt, Insulation Contractors Association. I think you have one of those blue cards up there for me.

PRESIDING MEMBER BYRON: No, I don't, but you're welcome to speak.

MR. BURT: Well, at any rate, I have four unrelated comments. First is that I note that this whole exercise operates very much on the way that a typical Wall Street economist does, namely things are going to go pretty much like they are. And that, I think, is a reasonable assumption here, except with one possibility.

We all recognize that energy prices are going up because of the increased demand from developing nations, especially China and India. And that since electricity is pretty inelastic it's pretty likely that your numbers are unlikely to be changed much by the typical small increases that we've seen lately.

But I'd caution that there's a possibility that like any market we could suddenly see a crisis jump, like doubling or more. And because government always attempts to respond to an economic crisis that bothers everybody, it strikes me that it would be wise for this Commission to have a small think tank somewhere with a job of preparing what your recommendation would be to do in such a case.

My other comments are not directly related to the Energy Commission's immediate responsibility, but they all have a very big impact on this issue.

First, I noted the brief exchange on cap-and-trade; and my comment on that is that it should work if you're not too ambitious. But I caution that we don't go into the error that Europe did because they were so afraid of the serious public adverse response to a near cutoff of electric supply until the eventual arrival of hoped-for nonfossil sources.

They made a gift to the electric utilities of very large offsets when they started their cap-and-trade. Well, several of those utilities, apparently under the assumption that either don't worry about tomorrow, when it comes we'll worry then, or that maybe Europe was not really serious about how much they're going to cut, sold a lot of those offsets for multi-million dollar profits.

And that's one reason that Europe actual increase -- decrease in use of $CO_2$ did not match the U.S., which does not have any such program. The only thought I would have is let's not be too ambitious. Remember that cap-and-trade did work on $SO_2$ where the quantities were much smaller. But as long as there is some effort to keep the market in a realistic look at what's available at reasonable prices, cap-and-trade should work.

My second point that is dear to my heart, probably the largest single energy efficiency potential in California today is in the millions of homes which were built here before about 1970, and all have empty walls.

The reason that that potential is very little realized is that in order to pump insulation into those walls you make holes, which no matter how repaired, are ugly. And therefore the homeowner is not going to be content to have a job finished until he sees a paint job on top of those holes which is increasing the cost.

My suggestion is that especially if cap-and-trade does increase the value of energy efficiency, that a program which offers a per square foot allowance for painting on any walls that are insulated would probably generate one whale of a lot of energy efficiency. And since that, among other things, would affect your peaks, it's certainly worth looking at.

The reason I say an allowance per square foot is that all of us who are much observant know that during the ZIP program that there were a large number of people in California eager to defraud. And therefore, I don't think we should offer to pay for paint jobs.

My last point is on cogeneration, and I'm not -- this doesn't apply to my own assignment, but as an engineer who stands and watches the way California works, it seems to me a terrible problem that considering the large number of large energy demand heat sources in California, that the trivial use we've made of cogeneration is a scandal.

And I think that it's hard to say why. My own guess is that there's a religious view that if we can't dispatch it, it's not power worth having. My own response to that is, hey, you're not dispatching the demand and you have to respond to that every damn minute.

So, I think some kind of a standing order, or some other thing which would encourage all those people out there that have got heat sources that can easily be converted to cogen, to start doing so would make a spectacular difference in California's energy efficiency.

With that, I complete my remarks, and I am happy to answer any questions or retire in disgrace.

PRESIDING MEMBER BYRON: No, thank you, Mr. Burt.

(Laughter.)

PRESIDING MEMBER BYRON: Thank you. How are things going at home with Mrs. Burt? Have you convinced her about compact fluorescent lights yet?

MR. BURT: Well, we have compact fluorescent lights in my study, and that's the only in our house because my wife hates the color.

(Laughter.)

MR. BROWN: Any additional comments? Commissioner Byron, any closing remarks?

PRESIDING MEMBER BYRON: Well, thank

you. This has been very informative. You know, I note that the Energy Commission has the long-run forecasting responsibility for the state. And the ISO has the responsibility for the operational reliability of the grid.

And there's a lot of expectation around getting our numbers to coordinate, to be the same, I suppose.

I agree with a lot of what Ms. Smutny-Jones said earlier today. They do an independent analysis, and it's a good objective check on what we do.

But our goals are different and our assumptions are different when we start out. I'm also -- I'd also note that in my tenure here at the Commission the forecasts are never correct.

I think the addition of the probablistic approach in recent years has done a lot to clarify the role of uncertainty. I'm reminded of the fact that doctors always project the birthdate of a child by using a little calculator, but only about 2 percent of all children are born on their projected birthdate. My point is forecasting is never correct.

So there is a risk that demand will

exceed capacity. We accept this risk as an economic necessity of not over-building capacity. And we work very hard on the most cost effective and economic ways to address this problem, outside of building more generating capacity.

So, speaking as a customer who's turned into an Energy Commissioner, I can tell you that customers rely upon this organization to make good forecasts, and they rely upon this organization and the ISO and others to make sure that we get it right.

So I'd like to thank everybody for being here today. Thank you for all of your input and comments. Very helpful. I hope you have a nice, but not too hot, summer.

(Laughter.)

PRESIDING MEMBER BYRON: We'll be adjourned.

(Whereupon, at 4:10 p.m., the Committee workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, RAMONA COTA, 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 3rd day of February, 2008.