JOINT PUBLIC MEETING

OF THE

CALIFORNIA ENERGY COMMISSION
CALIFORNIA PUBLIC UTILITIES COMMISSION

In the Matter of:)
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JOINT AGENCY ENERGY ACTION PLAN)
MEETING)
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CALIFORNIA ENERGY COMMISSION

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CALIFORNIA ENERGY COMMISSION

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John Bohn, Commissioner

Dian Grueneich, Commissioner

Rachelle Chong, Commissioner

STAFF

Steve Larson, Executive Director

Sean Gallagher, Energy Division

ALSO PRESENT

Dan Skopec, Acting Secretary, California Environmental Protection Agency

ALSO PRESENT

Sunne McPeak, Secretary, Business, Transportation
and Housing Agency

Yakout Mansour, President and Chief Executive
Officer
California Independent System Operator

Robin Smutny-Jones, Director of State Affairs
California Independent System Operator

Tom French
California Independent System Operator

Charles "Chuck" King
California Independent System Operator

Erik Saltmarsh, Executive Director
Electricity Oversight Board

Steve Brink
California Forestry Association

Brian Theaker
Williams Power

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Cogeneration Association of California

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Mid-Set Cogeneration Company

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P R O C E E D I N G S

10:11 a.m.

CHAIRPERSON DESMOND: I'd like to welcome everybody here today to the quarterly Joint Energy Agency Action Plan. We have a number of folks who are still on their way. But first, let me welcome everyone, as well as acknowledge the folks here upon the dais.

To my left we have CPUC Commissioner Rachelle Chong; and CPUC Commissioner John Bohn. We have Energy Commissioner John Geesman. To my immediate left is Acting CalEPA Secretary, Dan Skopec. To my right, PUC Commissioner Geoff Brown; CEC Commissioner Jim Boyd; and CEC Commissioner Art Rosenfeld. Also entering at the moment is PUC President, Mike Peevey.

So I am expecting a few other folks. Also sitting down here we have Yakout Mansour, President of the CalISO. And then the Executive Director, Steve Larson of the PUC. And B.B. Blevins, Executive Director of the Energy Commission.

So I'd like to welcome all these folks here today. We have a fairly full agenda and I would like to move quickly through this. So, I'm simply going to keep my remarks to a minimum, other than to note that this is a continuation in an effort initially started by President Peevey several years ago to insure that the agencies are coordinating their policy and implementation responsibilities in coordination with the Governor's directives, action plans, PUC orders and Energy Commission IEPR reports.

So, with that I'd like to turn to first President Peevey, and see if he has any comments. And then also anyone else here on dais who'd like to add some comments.

PRESIDENT PEEVEY: Nice to be here in Sacramento; nice day. Thank you.

CHAIRPERSON DESMOND: You're welcome. Is there anyone else who'd like to comment? Commissioner Geesman.

COMMISSIONER GEESMAN: I would hope that we could bring a new level of candor to our discussions today. The last several weeks we've gotten, I think, incontrovertible evidence that our renewables programs are not on a trajectory that we would like them to be.

The net system power report adopted by the Energy Commission on April 12th indicated that the contribution from eligible renewables in 2005 was 10.8 percent. Three years after the Energy Action Plan identified a 20 percent target for 2010, we have little measurable progress to show.

In fact, measured against 2002, the year that the Legislature created the program, renewables were 10.96 percent then. So we've actually regressed a bit.

More troublesome is the result of the PG&E solicitation announced a couple of weeks ago, the first procurement conducted under the CPUC's widely acclaimed December 2004 procurement decision. By all accounts, PG&E conducted a very robust solicitation. The December 2004 decision by the PUC had made renewables the rebuttable presumption for all procurement, the point made not once, but several times, in the PUC's decision.

That meant that before signing a contract with a fossil fuel project, the utility was expected to rebut the presumption that a renewable project would have met that need more effectively.

PG&E's solicitation resulted in four projects put forth as winners. They added a fifth a little more than a week ago. None of those five projects are renewable projects.

But more troublesome, of the 50 proposals that were received, not a single one of the proposals came from a renewable project.

Now, I want to be very clear. The utilities are not the enemy here. They are the delivery mechanism for state policy objectives. And I think that without making any comment on the merit or lack thereof of the individual winners from the solicitation, it would seem indisputable that as a means to accomplish our renewable objectives, the PG&E process was an abject failure.

I think that we need to have the awareness of recognizing when some of our policies are going astray. I think we need the honesty to objectively scrutinize what works and what doesn't work and the commitment to correct things that are broken as promptly as possible. And I hope we can begin that process today.

CHAIRPERSON DESMOND: Commissioner Geesman, I appreciate you taking that. I'm sure, and I would encourage all the Members here, as I have full confidence they will, to ask very good pointed questions today as we go through this.

We do have to shift from more of an emphasis on execution, given that I think it's fairly clear we're all in very broad agreement on what the principles and policies and objectives are.

So, with that, is there anyone else who'd like to make some opening statements or remarks?

Hearing none, why don't we begin with the first presentation. This is the summer 2006 preparedness discussion. First up is Dave Ashuckian from the Energy Commission to talk about the summer outlook. And if you could set the lights, please, so we can see that a little easier.

MR. ASHUCKIAN: Good morning, Commissioners, Secretaries, ladies and gentlemen of the audience. I've been asked to make my comments a little bit brief this morning. We're going to focus a little bit on the changes that we've made since the last EAP meeting, as well as coordinating efforts between the Energy Commission Staff and the ISO Staff.

Some of the activities that have changed since the last time we presented our outlook were updated demand response resources, updated interruptible resources, and some additional work on some probability assessments.

What we have incorporated or at least collaborated with for the first time this year at this point is looking at the resource adequacy filings and making sure that those are coordinated or at least compatible with what we're saying our resource outlook looks like.

And we've also continued to meet with the ISO to see and articulate the differences between how we do our methodologies of actually doing the analysis, itself.

Some of the things that have changed were we made some slight modifications, additions and retirements include Mojave and Hunter's Point for this year. And we've also made an adjustment to our forced outage rate. I'll talk about that in a minute.

The resource adequacy filings that we received in early February indicate that at least the municipal utilities are resource adequate for the summer. As you can see here we have broken down the type of resource that they have acquired under contract, and how much of that meets their expected load.

As you can see their own generation covers about 97 percent of the load. They have unit firm contracts for another about 4 percent. Their portfolio-backed contracts, about another 18 percent. Liquidated damage contracts for about 580 megawatts. And demand response for another 261 megawatts.

Now, in our statewide table we show about 3000 or so megawatts of plants that do not have contracts. These were the aging plants that didn't have contracts. This LD contract, these are liquidated damage contracts, many of those plants may have contracts under this. We don't have information about the specific contracts for those plants. So out of those 3000 or so megawatts on that line, at least 500 here are secured probably by the munis. Because these are facilities within, you know, access to those.

Now, I want to talk a little bit about the general methodology between the two, ISO versus ourselves. As you know, the ISO is responsible for managing the grid. Daily operational characteristics are very critical to how they operate the system. They worry about, you know, what's available on a real-time basis.

The conditions that they have to deal with at that moment are what they're used to having to take care of. And as a result they are much more concerned about what they see at any particular time.

Our analysis uses more of the historical system and what the capability of the resources are. We don't look at any specific hour-by-hour analysis of how the system would interact. But we know that, in fact, you know, for example when existing instate generation is up, it's likely that the imports would be down. As a converse, if the existing instate resources are down, imports would be up. And so we're looking at more the systemwide analysis of what the system should be capable of.

When you look at any individual thing by itself you might find differences there. And, in fact, it's pretty amazing. We're doing a completely separate and independent analysis, and when you look at the bottomlines of both methodologies we're actually pretty amazingly close.

On the statewide, this is just giving you an overview of the statewide control area. And a couple changes since the last time you've seen this, retirements on here are Mojave and Hunter's Point for about 1500 megawatts.

There is about, there's four plants -- I'm sorry, let's see -- there's a number of additions. And many of those are in the areas outside of the ISO. Those include Cosumnes, Walnut and Ripon.

And we've also again made an adjustment here to our outage rate to account for even the new additions. We're assuming now that even brand new additions have a 5 percent forced outage rate, so we're adding a little bit, about 85 megawatts, to our forced outage rate. And that is actually a change that we made after consulting with the ISO and how they do their outage rates.

And, again, at the bottom, line 21, there was some discussion about that in the past. These are plants that were identified in our aging power plant report. These are older plants that do not have existing contracts that we are aware of.

In fact, we found out that -- it became

public, I think El Segundo does have a contract. We took that off that list. And that is, again you'll see what the resource adequacy filings. It's likely that most of these plants probably do have contracts; we're just not aware of them at this point.

So, in fact, again, line 21 is included in the existing generation of line 1. We are assuming that it is available and will continue to be available this summer.

Moving on to SP-26, this has historically been the region of most concern, primarily because of the transmission constraints. I've eliminated going over through MP-26 at all, because it's pretty, as you've seen from our last update, which really hasn't changed too much, that it is quite adequate.

For SP-26, again, here the retirements include Mojave. The additions include Mountainview, Palomar and Riverside. And, again, we've made some slight adjustments for the outages on this, as well, for the new additions.

What you'll get in a moment here from Tom French from the ISO is their comparison. And as you'll see, actually we are within 1 percent of difference. Now, again, the way we do our existing generation is looking at what is the dependable summer capacity expected during summer temperatures. From there we take and separate out outages below, you know, on line 10.

So, the ISO looks at what the system actually performed last year, as what the existing system should be. And looking at those two completely different methodologies, we're actually within 1 percent. So we think it's actually a pretty good check and balance of actually how two separate complete analytical methodologies come out to be so close.

With that, I just wanted to give you one example of how the range of probable and possible numbers on these tables can change. This is a graph that shows you the probability of a specific level of demand occurring this year.

Now, this graph was created by using the Energy Commission's demand forecast and plotting what is an expected level of demand based on an expected level of temperature.

We take that demand-versus-temperature curve and apply it to all the historical temperatures that we've seen in California over the last 55 years. So it's the current demand forecast plotted against historical temperature.

And what this shows you is that based on historical temperatures the demand this year could range from anywhere from about 22,500, say, megawatts in south of Path 26; all the way up to a little over 31,000 megawatts.

Now, based on the historical most likely occurrence of temperature it looks like 27,027 would be the expected average of one and two level of demand based on that is the most likely occurrent of the temperature for this year. And, again, the actual demand could be anywhere on this mound peak, basically.

And we also show here in the light green what one standard deviation is. As you can see here, as you get over into the second standard deviation, that's a one-in-ten occurrence. So if you look at the far left scale, 10 percent probability equates to a one-in-ten year, one-in-ten possible. And, again, that shows that there's a one chance in ten that demand will be about, say, 29,500. There's also a one chance in ten that the demand would be as low as 24,750.

And with that, I'll let Tom French come

up and talk about the ISO's.

I will remain up here and then we can answer any questions you have after the ISO's presentation.

MR. FRENCH: Commissioners, ladies and gentlemen, I'm Tom French, Manager of Grid Assets, from the California ISO. Pleased to be here today in collaboration with the CEC to present our summer loads and resources operational outlook.

In terms of an introduction I do want to acknowledge that we do build off the CEC's electricity outlook. And we prepare a summer 2006 operational assessment. That incorporates normal variability of the operating environment.

And I just wanted to build off of Dave's last chart there. You saw the most likely condition and the standard deviations and so on around that. And that's what I mean about a reasonable range of forecasted conditions, is that there is the probability that conditions swing one way or the other.

Now, this brief assessment summarizes how the ISO may need to operate under forecasted - - some forecasted and some specific operating conditions in SP-26.

From an overall perspective, from a control area, load demand is expected to continue to grow this summer unless conservation is demonstrated or economic conditions change significantly. And load growth has averaged roughly 1000 megawatts a year over the last four years.

This year net dependable control area generation additions are in the range of approximately 370 megawatts. And that's the net generation. I think we added roughly 1800 megawatts, a little bit more than that, but with the retirements of Mojave and Hunter's Point, the net generation addition in the control area was roughly 370 megawatts.

And you can see that that generation will not keep up with the anticipated load growth. However, there are a number of transmission projects that will increase transmission import capacity, particularly in the south.

We've added roughly 800 megawatts to our import forecast compared to 2005. And, as Dave had indicated, the system has the capability for additional imports. However, the actual import levels are likely driven by markets, need and availability.

So the ISO is depending on taking advantage of those recent transmission upgrades, and the availability of increased imports to meet increasing demands. And just did want to acknowledge that the demand response and interruptible programs that we may need to call upon have increased in 2006 compared to 2005.

This is a summary of the SP-26 peak forecast. It's largely comparable, from a bottomline perspective, to the slides that Dave just presented. I believe when you look at the planning reserve in the area we have a 20.6. And the planning reserve, I believe, was somewhere right in the 22 range on the slide previously indicated.

We include a 1500 megawatt forced and planned outage rate in our determination of available generation capacity. We're aligned in terms of the import capacity at 10,100 megawatts, for a total supply of roughly 30,076. The most likely demand we're looking at is the 27,299 number. And so that leaves a reserve capacity in the south of Path 26 area of roughly 2800 megawatts.

And, again, that's for a most likely condition, which includes that average, middle-of-the-road place in the standard deviation chart that was shown earlier. All major lines and service, most likely economic conditions, average, forced and planned outage rates for generation, and incorporates our most likely import condition forecast.

I want to talk a little bit about this next chart because it does illustrate what we need to be planning for as a grid operator. The most likely forecast, as I indicated, were based on a set of assumptions where all lines are in service, average forced outage rates, the most probable average system conditions.

But however, there's normal variability in the operating environment. And we regularly see changes in generation forced outage rates from day to day which impacts the capacity available.

So what this chart indicates is the center bar was our most likely scenario for capacity available in the SP-26 area. The green line that runs across that particular chart is the most likely capacity need. And that's the capacity necessary to serve the one-in-two demand forecast.

And you can see by that particular line that runs across the chart, before we have to call on curtailable load or demand response interruptible programs, we'd have to have roughly 2500 or so megawatts in generation outages.

If we ran into that particular situation, again, there are plenty of megawatts available in those programs in order to restore adequate reserve margins.

On the other hand, going out to the extreme one-in-ten capacity need, -- let me go back. The one-in-two also incorporates a 2000 megawatt outage. So you not only have 1500 megawatts of generation offline, which is the equivalent to a San Onofre or a Mountainview or three Mountainview units -- or two Mountainview units and another large unit, such as Palomar, but it also includes the loss of about 2000 megawatts of import capacity.

And so, again, looking at that one-in-two line, you have to have a number of events occur before you even need to call on the demand response and interruptible programs in the SP-26 area.

However, when you go up to the extreme capacity need, that's a one-in-ten temperature and which is farther out, close to the two standard deviation area on the chart that Dave presented, if you have an extreme temperature condition, depending upon your outage rate, under our most likely scenario -- and again, keep in mind that it's the loss of -- you'd have to have a loss of 1500 megawatts in generating units, compounded with high temperatures, compounded with the loss of 2000 megawatts of imports before under the most likely capacity scenario you'd be under water there.

On the other hand, if your generation rate is low, it appears that there's the possibility that we could manage all of those conditions, calling on demand response and interruptible programs.

So, from an operator's perspective, this takes the numbers that you see in charts, tries to operationalize them, give you a view of the possible circumstances that we may be up against. And I just want to point out that last year during system peak in the SP-26 area we actually had 2700 megawatts in generation outages, but we didn't have high temperatures. And so there was a limited amount of demand response that needed to be called on in 2005 to manage that particular scenario.

CHAIRPERSON DESMOND: Tom, I think Commissioner Brown has a quick question.

COMMISSIONER BROWN: Yeah, when you say that you can call on demand response programs, what are you speaking to, specifically?

MR. FRENCH: Well, there's a number of -- the demand response would be --

CHAIRPERSON DESMOND: A/C cycling.

MR. FRENCH: Yeah, A/C cycling, as an example.

In conclusion, the amount of risk associated with summer 2006 operation in the SP-26 area is similar to slightly improved to that of the summer of 2005. And by that I mean most of the additions, the gen additions and the import capability were largely in the south. So there's a slight improvement in that situation, although as you've seen, depending upon the circumstances, the compounded circumstances, there's still the possibility for problems.

You've seen how those forecasts

translate into the historical real-time operating environment. The ISO is counting on a completion of transmission upgrades and generation additions which are largely complete at this point in time, the transmission upgrades not so much, to capture a moderate amount of additional supply.

However, continuing increases in demand response and contracted interruptible programs will help the ISO manage adverse conditions.

Increased imports and conservation will continue to be an important factor to help meet demand. We're relying on those increased imports this year if we see the load show up like it should have last year.

And just in summary, under extreme conditions low probability we do plan. We have a number of plans, not only from an operating procedure perspective, but to call upon demand response and interruptible programs, as well as there is the possibility, under those compounded conditions, that it would require firm load shedding to restore reserve margins.

CHAIRPERSON DESMOND: Thank you, Tom. Yes, Commissioner Geesman.

COMMISSIONER GEESMAN: Tom, you were a

little ambiguous on transmission upgrades. Are there still upgrades that you expect to come online before the summer that you're counting on?

MR. FRENCH: Yes, there's some capacitor projects on the SWPPL and Palo Verde-Devers line. Last year Palo Verde-Devers experienced some low voltage and so on.

Those projects are still under construction. We're expecting a majority of the work to be completed by July 1st at this point. But we do need to continue to raise those as a high priority.

COMMISSIONER GEESMAN: Thank you.

MR. FRENCH: In terms of summer preparedness we are performing engineering studies and developing operating tools and procedures to remedy any issues that we see.

We are talking or engaged in the long-term procurement proceedings to give the operators perspective on long-term procurement needs.

We're in the process of rolling out annual summer conservation campaign coordinated with the statewide Flex-Your-Power-Now program. We're promoting a Save-A-Watt voluntary load reduction program. We need to keep the pressure on transmission line upgrades in the south, get them completed before summer peak.

We have staff out meeting with the utilities, the generators in WECC control areas to discuss supply and demand outlook and unit readiness in particular.

And, again, the chart illustrating the outage rates. If those units stay available, we have a real good shot at managing some pretty bad circumstances should they occur.

We're completing our summer workshops to prepare the ISO and utility dispatchers for summer peak conditions. We are assessing utility procurement plans as it pertains to the resource adequacy requirements. And we're participating in the regional supply and demand assessments of the WECC to determine areas of excess or deficiencies in neighboring control areas. And largely what we're seeing there is that supply in the west and the demand seem to be keeping pack with each other.

CHAIRPERSON DESMOND: Thank you, Tom. First, let me acknowledge and welcome Secretary Sunne McPeak, who joined us here during the presentation. Thank you for coming today.

And, also, I'd like to commend, Tom, both you and Dave and the staff at the CEC and the ISO for doing a good job in moving towards what the Governor had asked for, and that is more risk management based and probablistic based planning methodologies. I think that gives people a much better feel for the confidence level and what the range of expected possible outcomes is, as opposed to the past.

So, do we have questions here from folks? Secretary McPeak.

SECRETARY McPEAK: Thank you, Mr. Chairman. I'm just looking at the preparedness actions in the previous presentation, as well. I think it may be obvious, but it's worth stating since I don't actually see it explicitly, that as of May all three agencies are going to do their weekly check-ins, too. And it's really important that that happen.

This talks about meeting with utilities and generators, but if we don't have that weekly check-in of the CEC and the Cal-ISO and the PUC, then we don't necessarily get the real-time synch up of what's going on.

CHAIRPERSON DESMOND: Thank you.

President Peevey.

PRESIDENT PEEVEY: This morning, the Energy Commission -- you'll have to help me with my memory loss here -- but on your chart on SP-26, the last line, 21, the aging generation without capacity contracts 2370 megawatts. How is that factored in here in SP-26 in terms of being able to call upon this in time of need? I've --

MR. ASHUCKIAN: Again, those are plants that are currently operational in the system that we're counting as if they are here. They were identified back in 2004 as potentially high risk of retirement based on the fact that they did not have contracts.

With resource adequacy we believe many of those have contracts at this point. We don't have information to unequivocally say that they do, and therefore we're keeping them here as a potential. But they are counted as if they're operational.

PRESIDENT PEEVEY: So they are incorporated in the lines above 21?

MR. ASHUCKIAN: Correct, they are incorporated in line 1 as existing generation.

PRESIDENT PEEVEY: I got'cha, okay.

Minus the muni fees that you spoke to where you have some certainty that --

MR. ASHUCKIAN: Correct, --

PRESIDENT PEEVEY: -- they're --

MR. ASHUCKIAN: -- correct.

PRESIDENT PEEVEY: Okay.

MR. ASHUCKIAN: Now, you'll hear later on IOU resource adequacy. And so we think that it's likely that, you know, based on the results of both IOU and munis, resource adequacy for this summer that enough generation has been secured for the summer.

PRESIDENT PEEVEY: Okay. And this doesn't explicitly show for the IOUs, per se, how much of this muni capacity, nearly 25 percent, well, I won't say in excess, but it would be available in times of a pinch, does it?

MR. ASHUCKIAN: I'm sorry, I don't quite understand the question.

PRESIDENT PEEVEY: The munis in southern California in particular have some excess capacity, let's put it that way. You've got it in here, for the state, as a whole, broken down by --

MR. ASHUCKIAN: I see, --

PRESIDENT PEEVEY: -- firm, contracts --

MR. ASHUCKIAN: -- yeah.

PRESIDENT PEEVEY: -- and all that. But the Energy Commission, do you -- this is my question -- on your page -- well, our page 3, 2006 ISO's southern region, SP-26, you don't explicitly -- do you take into consideration some portion of that muni excess?

MR. ASHUCKIAN: No. We are assuming that this is only what the ISO has available to it. Not what is excess --

PRESIDENT PEEVEY: Doesn't that give somewhat of a false picture to some degree?

MR. ASHUCKIAN: Well, and that's where you look at the statewide, that shows you what the potential balance is of all the resources in the state.

PRESIDENT PEEVEY: I understand that, but in either case, doesn't it give somewhat a false indication of a narrow margin than in fact, in a time of need, could be called upon? That's my question.

MR. FRENCH: I can try and answer that question. Similar to the chart that I displayed for SP-26, depending upon largely the most likely condition, which typically the charts are geared to, for the most part, take into account average outage rates, average demands and so on.

If we're experiencing a regionwide heat wave, depending upon the conditions in each particular muni, there may or may not be capacity available in the market to supplement let's say the ISO's control area need.

So, it's possible it could be there and it's possible that it may not, depending upon the outages that a muni may be experiencing, and depending upon whether they're experiencing one-in-ten demands or one-in-two demands.

COMMISSIONER BROWN: Is there anything that stops the muni from selling that power to another state, for example, if they have a regionwide heat wave, like in Arizona?

MR. FRENCH: Not to my knowledge.

MR. MANSOUR: Maybe I should add something, President Peevey, to your question. We are actually discussing with the munis, particularly L.A., on arrangements by which under emergency conditions we can call upon what is available in L.A.

There's some commercial issues that we are working on to resolve before the summer hopefully. And also L.A. is committed that they will work with us operationally in preparation for the summer.

So, through those activities we will identify what we would need from each other to support each other. It's not just them helping us. Obviously, it shows that there are plans where they need our help, too. And we stand ready for that, too.

So, I can assure you that the communications this year is a lot better than last year in terms of getting prepared as a state, especially in the south part, as an operating unit.

PRESIDENT PEEVEY: I want to commend you, Mr. Mansour, for your efforts over the past nine months to insure better communications between Cal-ISO and DWP. I think it's proven fruitful, it was a little tough at times, but you got their attention.

MR. MANSOUR: And I can't say enough about really their leadership, as well. It takes two to dance, and it was not quite dancing, but they responded very well. The leadership is committed and our staff have the instructions clear.

CHAIRPERSON DESMOND: Mr. Skopec.

ACTING SECRETARY SKOPEC: Back to the initial question, on line 21, when will you know when those plants without contracts, whether they've been picked up by resource adequacy requirements or not?

MR. ASHUCKIAN: We may never know for sure; contracts are potentially confidential information. However, because resource adequacy has indicated that sufficient capacity has been secured, we can assume that those plants meet, are part of that package.

It's possible that they aren't, that they're some other capacity they've secured outside of California. But, it appears that it's okay.

MR. MANSOUR: Maybe I can add something to that, too. We were concerned that without a contract generators like this would not have incentive to stay. Basically, why would they stay? They are expensive to run; they don't have contracts. And when you call upon them you pay them for energy, you know, in real time pretty much, so the liability was free at that time.

Mr. Skopec, and most of you know the RCST proposal that's in front of FERC as we speak, which hopefully will be resolved or addressed before the summer, provides a capacity payment that did not exist in the past.

So those units have another mechanism to be paid if they do not have contracts to fully cover their costs from contracts. And that did not exist last year, so we have a number of mechanisms this year that were not available to us last year.

CHAIRPERSON DESMOND: Any further questions? Thank you.

At this time I'd like to move to the next item on the agenda, the Energy Action Plan Staff priority activities. We have three presentations, the joint CPUC/CEC, Mr. Blevins and Mr. Larson; the Cal-ISO, Mr. Mansour, again; and the Electricity Oversight Board, Erik Saltmarsh. There you are, thank you. You're welcome to join us up here, too, Erik. I believe there's a seat available for you.

Are we all set?

EXECUTIVE DIRECTOR BLEVINS: Yes.

CHAIRPERSON DESMOND: Please. Thank

you.

EXECUTIVE DIRECTOR BLEVINS: Good morning, all. I'm B.B. Blevins, Executive Director of the Energy Commission. And Steve Larson, the Executive Director of the California Public Utilities Commission, and I are going to endeavor to tag-team this presentation.

As you know, the Energy Action Plan has nine specific policy goals. Arrayed under those nine policy goals are approximately 100 activities.

We're going to, this morning, indicate approximately 30 of those activities that are our highest priority from the staff standpoint at this moment.

I was told this presentation is supposed to take about ten minutes, which works out to about 20 seconds an activity. So, we're going to try to move through this fairly rapidly.

The first goal, as it should be, for the Energy Action Plan is energy efficiency. There are three specific priorities that the staff has been focused on.

Obviously the first is we're endeavoring to integrate cost effective efficiency into the resource plans on an equal basis with supply side resources. There's a particular focus there on residential and commercial lighting and air conditioning for peak reduction purposes.

We are continuing to work toward the adoption of the 2006/2008 energy efficiency programs, the portfolios and funding. We're monitoring the program roll-out.

We are also working on developing the protocols for the evaluation programs. And those protocols are expected to be available, I believe, in May 2006. And they will be then seen as items to move into the procurement and other regulatory activities.

The third high priority has been the implementation of the actions outlined in the Governor's green building action plan. This is going to continue through 2006. And we continue to participate in all the joint meetings in association with the green buildings initiative.

And that's what I had for goal one.

MR. LARSON: Okay, the second goal is demand response. And our priorities include the issuing of decisions on proposals for statewide installation of advanced meters, and for small commercial and residential IOU customers. And it's expected that there will be proposed decisions in July of 2006, at least for PG&E; and in November for SDG&E.

Also, another objective is to create standardized monitoring and evaluation, known as M&E mechanisms, to insure that demand response savings are verifiable. And we've issued a scoping workshop and circulated draft protocols for estimating cost effectiveness. Comments are due May 1, 2006.

A third objective is to expedite decisions on dynamic pricing tariffs to allow increased participation for the summer of 2006. And to encourage load shifting that does not increase consumption. There is the proposed decision for default critical peak pricing was rejected by the settling parties, and we moved on from there to an alternate decision which would accept a settlement which is voluntary, which is being circulated.

The fourth objective is to identify and adopt new programs and revise current programs to achieve the goal of 5 percent demand response by 2007. In March the Public Utilities Commission authorized demand response program budgets, the program offerings in a program development process for the large customers for 2006 to 2008.

B.B.

EXECUTIVE DIRECTOR BLEVINS: Goal three is renewables. Four specific high-priority areas there. The IOU RPS is clearly on the list. There is our attempt to insure new transmission lines, the construction of new transmission lines to access renewable resources.

There's the implementation of the Governor's solar initiative. And then there's the implementation of the RPS standards for the ESPs and the CCAs.

Relative to the RPS solicitations, all three IOUs have completed the 2005 solicitation and their short lists have been submitted.

The Energy Commission, in two days, expects to adopt the RPS guidebook for eligibility for the renewable facilities program and the overall program. Called out on the chart here, PG&E has 120 megawatt geothermal facility pending CPUC approval.

Work in terms of assuring transmission. We have the CEC completing the first biennial strategic transmission plan with its associated recommendations. And then the CPUC has recently opened a new OII that's designed to address RPS transmission issues.

The Governor's solar initiative, we certainly have the CPUC's landmark funding decision of $2.8 billion for solar in the existing IOU commercial and residential sector. And the CEC is focusing its $350 million on new residential construction in support of the same program.

And then the CPUC's RPS rulemaking is now beginning to examine the establishment of the rules for the ESPs and the CCAs in terms of the RPS standards.

MR. LARSON: The fourth goal is electricity adequacy reliability and infrastructure. There to insure all load-serving entities meet the state's adopted reserve and resource adequacy requirements of a 15 to 17 percent planning reserve no later than June 2006.

The PUC has adopted resource adequacy requirements in October 2005. And PUC/CEC are coordinating on program implementation and filing review.

Also in phase one there is a resolution local resource adequacy on schedule for June 2006 decision at the PUC.

Another important objective in this area is the establishment of appropriate incentives for the development and operation of new generation to replace the least efficient, the least environmentally sound.

The long-term procurement rulemaking is in phase one, and it addresses impediments to investments in new generation and a decision is expected in that matter in June of 2006.

Goal number five, which is the electricity market structure, a high priority is to complete and refine, as necessary, the current IOU electricity procurement process, provide that it is competitive, that it's transparent, fair; that it proceeds in a timely fashion.

And there are rulemakings underway. Phase two will review the IOUs' ten-year long-term procurement plans. And then another rulemaking. We're also evaluating confidentiality, transparency issues related to procurement.

Another objective in this area of goal five is to complete and implement by February of

2007 the ISO's market redesign and technology upgrade known as the MRTU, to reform California's wholesale electricity market.

The PUC continues to file comments and negotiate with stakeholders in this matter for the MRTU. The ISO made a tariff filing at the end of January and intends to implement MRTU by the summer of 2005.

A third important objective is to foster sound market rules; to increase the regulatory certainty and improve coordination with the west's electrical system. And the PUC is coordinating very closely with stakeholders and advocating at the FERC.

EXECUTIVE DIRECTOR BLEVINS: Goal number six, natural gas supply, demand and infrastructure. Three priorities there. I should note that that should be number 3 instead of number 8, associated with the first-time priority.

These priorities are focused specifically on creating infrastructure and assuring that it's adequate. CPUC is examining infrastructure adequacy in its natural gas OIR. It's issued a report on electric IOU gas needs and authorized expanded hedging program reviews reviewing -- proposal for storage expansion. And also note here PG&E is to proceed with the added line at McDonald Island storage.

The natural gas working group continues to work together and discussion of inviting FERC to participate on occasion. And the utility study was recently completed on the impact of high natural gas prices on the California economy.

There's the work to establish standards for new transmission storage capacity additions and the associated issues with that activity. The LNG working group continues to meet monthly to coordinate information. We have the DOE forum coming up in Los Angeles on June 1st that we are all currently working toward.

The CPUC has approved the open access tariffs, and the CPUC is to receive written and oral testimony on the need for and the design of the standards associated with the storage capacity additions and associated issues.

And then finally, as we move to global natural gas supplies, we all know that natural gas in the world is not created equally. It has various combustion and emission characteristics based on where it originates from. And the CEC is continuing to work with the PUC with regard to research into the quality and nature of those gas supplies and their impacts on the emissions of California.

ARB is also examining its rules in relation to this issue with us. We are executing emission testing contracts for turbines and larger burners and appliances to evaluate the different supply types relative to those technologies. And again, the CPUC is examining natural gas quality in its natural gas OIR.

Transportation fuels, supply and demand and infrastructure, goal number seven. We, specifically the CEC, continue to increase our coordination on petroleum infrastructure permitting and develop guideline principles for facility permitting. Obviously working toward a goal where we can have a more common permitting process at all levels of government. Working toward a package of best permitting practices by June 2006.

We continue to work with other states and stakeholders with regard to improving CAFE standards. This tends to be a moment-by-moment activity, as the opportunity presents itself. The last opportunity was submitting comments to the National Highway Traffic Safety Association on their rulemaking for light truck efficiency this past year.

We continue to support, through both the fuel cell partnership and developing bids for federal dollars, working with Cal-EPA to implement the California hydrogen highway blueprint.

And then the CEC is beginning in earnest its work in association with legislation SB-1007 -- I'm sorry, go ahead, Mr. Chairman.

CHAIRPERSON DESMOND: I was just going to add right there we also just completed the interagency bioenergy plan, which included a significant portion on the biofuels, both ethanol and biodiesel. And I know it just gets edited down, but I didn't want people to lose sight of that effort.

EXECUTIVE DIRECTOR BLEVINS: No, that was a significant effort.

On the SB-1007 work we are working closely with ARB as the statute requires us to do so. We are actually shooting to try to complete that work by December 2006, despite the fact that the legislation gives us till July 2007.

And that's it for goal number seven.

MR. LARSON: Goal eight deals with research development and demonstration. There our high priorities include the allocation and prioritization of RD&D funding for energy efficiency and demand response.

The CEC activities are underway to support green buildings, efficient lighting, programmable communicating thermostats and other DR, plus distributed generation.

Another objective is to align RD&D funding with public policy goals for renewables and greenhouse gas mitigation. The PUC solar order set aside funding for solar RD&D. The CEC is conducting research on zero energy homes, cross-cutting benefits of energy storage and so forth.

The natural gas RD&D. The CEC is implementing the natural gas RD&D plan, which was approved by the PUC. Bulk transmission RD&D, the CEC has established projects on systems for optimization and new capacity infrastructure, real-time system operations and planning tools.

EXECUTIVE DIRECTOR BLEVINS: Goal nine, climate change. Highest priority is support for implementation of the motor vehicle greenhouse regulations; legislation sponsored by Assemblyman Pavley. We continue to provide the support as needed in relation to the implementation of those regulations and the issues that are finding themselves in the judicial arena.

We have the Climate Action Team report that was just submitted to the Governor and the Legislature for consideration. We are continuing to pursue the recommendations listed in that report for both of our agencies. Specifically the Energy Commission is working toward a voluntary municipal utility program to have them develop a greenhouse gas emissions reduction program.

We have our energy efficiency programs. The California Public Utilities Commission is working to adopt energy efficiency programs for 2006/2008 that I mentioned earlier. And we're also trying to develop the baseline forecast against which all future greenhouse gas reduction savings can be measured.

The last item on the chart there is certainly not the last on this chart, or certainly not the last in this package, is the significant policy direction that both the California Energy

Commission and the California Public Utilities Commission has taken in the past few months with regard to greenhouse gas performance standards; and the expectations of how the CO2 characteristics of emissions that are expected from electricity consumed in California into the future.

Last bullet, CEC Staff monitors the application of the GHG adder as it is applied to projects in the IOU-sponsored long-term RFOs. And the PUC, I believe, began its OIR a couple of weeks ago specifically on the greenhouse gas performance targets.

That's the complete package and both of us are available for questions.

CHAIRPERSON DESMOND: Great. First let me thank you for the efficiency with which the two of you divided that up. It was pretty good.

Commissioner Geesman.

COMMISSIONER GEESMAN: I have a question on goal three, renewables. And it's item 7 in our book. Insure new transmission lines are built to access renewable resources.

I note that San Diego Gas and Electric has withdrawn its application for the Sunrise

Power Link and presumably will refile a new application at some point this summer. They had attempted to bifurcate the determination of need from the selection of a particular route which is consistent with a lot of the recommendations the Energy Commission has previously made.

Can either one of you gentlemen tell how the process has changed for a CPCN since San Diego had initially filed its Valley-Rainbow CPCN application in 2000? Seems to me we're headed down the same old road to the large-scale gladiatorial shootout. We've had a number of years to work on changing the process, but I don't perceive any changes.

COMMISSIONER BROWN: Commissioner Geesman, I would just say, as one of the sinners in the Rainbow, before you get started, that there hasn't been any problem with the PUC. The delays that have been occasioned are really the voluntary actions of SDG&E to refine and to improve the submission.

I think that they understood that the Commission was ready and receptive to take their proposal and look at it and deal with it promptly.

MR. GALLAGHER: Commissioner Geesman,

I'm Sean Gallagher, the Director of the Energy Division at the PUC.

The Sunrise project has changed so much since it was originally filed here. You're probably aware that now San Diego has an agreement with IID for joint ownership of the project. And it's my understanding that that's what's occasioned the withdrawal and the refiling of the application.

Our environmental team is already working with both SDG&E and IID and the BLM to insure that that permitting process, at least the environmental portion of the permitting process, occurs smoothly and efficiently.

We will, of course, allow parties to participate in that proceeding and make their points. One of the things that we're going to try to do this time around that's different from Valley-Rainbow is take something of a longer view of things.

I think in Valley-Rainbow one of the issues was that the outlook was only about five years. And for projects of this size it may not be appropriate to limit the outlook to that timeframe.

But under the due process rules that we operate under we're certainly going to allow parties that have concerns with this proposal to articulate those concerns to us. And we hope to resolve those concerns in an extant fashion, or at least in a efficient fashion.

COMMISSIONER GEESMAN: What role will the Energy Commission's adopted strategic transmission plan play in your process?

MR. GALLAGHER: I guess I don't have a specific answer for that. My understanding is that when the strategic transmission plan was adopted last year it did recommend adoption of the Sunrise project. But the Sunrise project there -- at that point Sunrise project had not been defined in very great detail. So I'm not exactly sure how we take that Energy Commission output and work it into our procedure.

COMMISSIONER GEESMAN: And for a number of years there was discussion as to how you were going to embrace the ISO's approach to determinations of need. What changes have been made in that area?

MR. GALLAGHER: The forum in which that's being addressed is the Devers-Palo Verde case, in which the issue has been raised. And I'll be honest with you, I don't have in mind exactly what the procedural status of that case is.

But the question is how do we take into account the fact that the ISO has made a need determination. In this case I don't believe the ISO has yet made its need determination for Sunrise. It's a little bit unusual that the timing has worked out the way it has.

But we're looking into whether we can simply accept the ISO's recommendation; defer in some manner to it; make it rebuttable presumption. Those issues are being addressed in the companion investigation to the Devers-Palo Verde case.

COMMISSIONER GEESMAN: You don't have much of a track record on rebuttable presumption, so. At least in the renewables area.

Thank you.

CHAIRPERSON DESMOND: Thank you, Commissioner Geesman. Commissioner Boyd.

COMMISSIONER BOYD: Gentlemen, as you know, in both the AP-1 and -2, and in the two major Integrated Energy Policy Reports, 2003 and certainly 2005, these combined agencies put a lot of emphasis on distributed generation, combined heat and power in particular.

And I didn't hear any reference to where we stand in that arena in your progress against plan. Could you give me a general idea of where you think we are in terms of progress against plan with regard to the commitments that have been made in the Energy Action Plan, as well as our own individual energy report?

MR. GALLAGHER: I'm sorry, Commissioner Boyd, you were asking about distributed generation and combined heat and power. The progress we've made on distributed generation, probably the most significant progress is the adoption of the California solar initiative.

We do also continue to have the self-generation incentive program. Much of the funding for that program is directed at solar for this year, but there still remains an increment of funding that is available to other distributed generation technologies.

The specific question on combined heat and power, in the Commission's planning documents that we submitted to the Climate Action Team, we've identified that as an area to which we must bring specific focus. We don't have -- I don't have a report for you on specific actions we've taken with respect to combined heat and power at this point.

Although probably what I should mention is there's the ongoing QF proceedings at the Commission. Many of the QFs, of course, are cogeneration facilities. And one of the big issues for them is what are we going to do with avoided costs pricing after the expiration of the five-year contract extensions which come up this year. We've got a decision on that issue scheduled to come out in a couple of months.

COMMISSIONER BOYD: Okay.

EXECUTIVE DIRECTOR BLEVINS: And, Commissioner Boyd, if I might just add one small comment. You'll recall that in the Climate Action Team process, as not part of the executive summary report, but in the many attachments, the thicker document, we were -- both the PUC and ourselves were asked to go off and develop work plans for specific areas.

And so there's greater specificity there that we can rely on and share with folks on those items.

COMMISSIONER BOYD: Okay, well, I appreciate the update. And the Climate Action Team report may have to be the major forcing function. This is an area that has been of extreme interest to me over the years. And I'm just fearful that at the end of this year when my term is up, we won't have moved the ball as far down the field as we talked about two, three and four years ago.

So, I remain committed and concerned that we aren't taking enough advantage of the opportunities offered there. But, more to follow, I guess.

CHAIRPERSON DESMOND: Secretary McPeak.

SECRETARY McPEAK: Thank you, Mr. Chairman. I think what we have is -- I'm going to check on what we are doing right now -- the presentation was to take from all of the items on the Energy Action Plan II and set forth the priorities that are before us for approval for action.

And as you said, this is in a summary form, so some of it may be implied or it may not be. so there are three things that I actually want to ask about.

The first is in terms of the solar initiative, do we have a focus in your priority action plan on solar on state buildings or state-funded buildings.

Number two, given the timetable that is in Energy Action II for building standards and dynamic pricing and advanced metering, and also the reference in this priority list of trying to accelerate or encourage that, where do we stand in trying to get advanced metering into new construction. And hopefully not wait till the 2008 building standards for new construction.

And three, Mr. Chairman, you mentioned biofuels. And recently the military had raised that issue, and particularly the Navy, about making sure that they have an adequate supply and asking what more we can do to insure that there is enough demand so that they can rely on a sufficient supply of biofuels to meet their federal directive of 20 percent.

So, maybe you could actually reference that, that's more of an information item. The first two I'm asking about for the Energy Action Plan II and this list of priorities in the workplan. Do we have either the solar on state buildings, and/or dynamic -- excuse me, advanced metering in new construction.

EXECUTIVE DIRECTOR BLEVINS: News construction. In terms of the solar on state buildings, my understanding is that that was potentially a component of the green building initiative. So, -- and I'm going to have -- come on up, Valerie -- I'm going to have --

CHAIRPERSON DESMOND: I was going to say I understand we've already begun the process on new construction, major renovations on the Energy Commission's portion. And then I think Mr. Gallagher can probably update.

But, Ms. Hall.

MS. HALL: Certainly renewables is an important part and needs to be an important part of the green buildings initiative. We have been working with the Department of General Services to look at how we can accelerate both the use of both efficiency and renewables in those buildings.

I think that we are in talking stages. I don't know that there is specific tangible results of that yet. But we certainly have that as one of our goals.

SECRETARY McPEAK: So it is a part of

this priority workplan, is that true? That's what I'm really trying to discern. I mean the green buildings program is referenced and we have the solar initiative. I'm just -- but it's not explicit. I'm trying to make sure that I understand that it is, indeed, a part of this priority workplan.

MS. HALL: I think that was just perhaps some poor wording on our part as we were feeding that information up. Yes, it is truly a part of the overall plan.

SECRETARY McPEAK: Great, okay.

CHAIRPERSON DESMOND: Secretary, I also would add that Commissioner Pfannenstiel, who could not be with us here today, is very active on that green buildings team. And I know for sure, having spoken with her directly, that she expects it as part of that plan, so.

SECRETARY McPEAK: She and I are Co-Chairs, and I really rely upon her.

Okay, and then the second being the advanced metering in new construction. Of course, she would want me to ask that question.

MR. GALLAGHER: I've heard that question from you before. Just on the solar I wanted to just go back and say, there's not a specific component of the solar program that our Commission has adopted that's directed at state buildings.

We are, though, looking at creating performance-based incentives, that is, providing the rebates based on performance of the solar installations rather than the capacity.

And one of the things we'll be doing when we look at that is awarding, for example, high rebates to tax exempt facilities, or tax exempt entities like state buildings, than to taxable entities. And that's because there's a tax credit for entities that have to pay taxes and tax exempt entities, of course, don't get that same credit.

So, that will address, to some extent, the state buildings, but also other buildings like schools and churches and things.

SECRETARY McPEAK: With big roofs.

MR. GALLAGHER: With big roofs. On the advanced meters for new construction currently I'm afraid to say we haven't made progress on that goal. I think the intent is to, once we get these advanced metering cases through the Commission, we're going to start rolling out meters both to new and existing customers. But there's not a specific program at this time that's going to insure installation of advanced meters in new construction.

SECRETARY McPEAK: Biofuels can -- maybe, Mr. Chairman, you can -- biofuels in the military.

CHAIRPERSON DESMOND: In fact, I'd actually ask Commissioner Boyd who chaired the bioenergy planning interagency working effort to comment on that.

COMMISSIONER BOYD: Well, the military, as you know, has gotten a law passed in this state that provides that B-20 is available to them, can be used in military applications. Otherwise, B-20 has not yet been deemed a viable fuel in the California arena.

Engine manufacturers will only warrant their engines at a level of B-5. The biofuels report that we just submitted very heavily pushes the idea of going deeper into, of course, biofuels, but biodiesel in particular, B-2, B-5, B-20, to try and get all the hurdles out of the way.

And they are -- there are two hurdles.

Air quality issues that need to be resolved, and fuel quality issues. The military says they want to use B-20 to meet their EPAC requirements; but they are requiring that the fuels they receive meet military specifications. We can't do that in the civilian world.

So we are discussing within the affected state agencies, that means ourselves, the ARB and Weights and Measures of the Food and Agriculture, the idea of California initiating actions on a fuel quality standard, so that the manufacturers of engines would be willing to certify -- increase their emissions and warranties for their engines to a higher level of, let's say, biodiesel.

We've gotten -- the ASTM, which is the national standard setting board, is working on this subject. But we got agreement in our hearings here that they move with glacial alacrity and there's support for the State of California, unusual support from both vehicle manufacturers and fuel suppliers, for the State of California to move out on its own and provide a standard that may prove to be leadership to the rest of the nation on that subject.

And we hope to actively pursue that idea and we're in discussions literally now with the other agencies to move forward on that.

SECRETARY McPEAK: Can I -- just one last question. Timeframe on working with the other agencies on it?

COMMISSIONER BOYD: Well, we're working right now, but we have submitted a bioenergy plan to the Governor and we're waiting, frankly, for some reaction to and feedback on that detailed plan, which has time schedules in it, which is to move out right away. But we need -- he asked for the report. We provided the report. We're asking for some -- we're waiting for feedback on some of the proposals within that.

And, you know, we're expecting there will be some form of action plan from the Governor in the not-too-distant future.

SECRETARY McPEAK: Thank you.

CHAIRPERSON DESMOND: President Peevey.

PRESIDENT PEEVEY: Just to augment the response on the solar and AMI, excuse me, AMI. Before us at the PUC in June will be a decision in the PG&E proposal. And PG&E is already putting in 5000 meters in Vacaville, where some of you traveled through today.

If that program is approved for PG&E in its entirety, I could assure you that PG&E will not start putting in these meters in western San Francisco and in Pacifica and in Monterey. They will be doing it in areas of, you know, newer homes and in areas of higher climatic intensity. With the exception of Geoff Brown's house in west San Francisco.

(Laughter.)

PRESIDENT PEEVEY: But the full augmentation of the program of new construction, I think, awaits to a significant degree the Energy Commission's further adoption of the new building standards, does it not, Mr. Rosenfeld? Yeah.

COMMISSIONER ROSENFELD: Finally. We're going to have a staff presentation next on those. I think the good news is we want to tell you that I'm afraid we won't have them in place until 2008. But in the 2008 building standards we will have new meters in -- we'll have AMI meters in all new homes, and programmable communicating thermostats, so that we will be able to go in for demand response.

But we don't seem to be able to get it on track for before 2008.

CHAIRPERSON DESMOND: Any further questions? No? With that, we'll move on to the next presentation. Mr. -- thank you very much.

We're going to switch to Chuck King at the ISO. Mr. King.

MR. KING: Good morning, President Peevey, Chairman Desmond and Panel Members. I'm Charles King, I go by Chuck, Vice President of Market Development and Program Management at the California ISO.

Along with overseeing the implementation of the ISO's market design and technology upgrade, MRTU program, I'm also the executive responsible for overseeing market development which will include demand response programs.

And what I'd like to do this morning is briefly share with you my perspective on the role of demand response in the wholesale markets, based in large part on my prior experience with the New York ISO.

CHAIRPERSON DESMOND: Thank you. Before, proceedings, Mr. Kelly, do we have Mr. King's presentation available for projection?

MR. KING: I just have -- I'm just going to make some comments. I don't have a formal presentation --

CHAIRPERSON DESMOND: Okay, I have a document here, thank you.

EXECUTIVE DIRECTOR BLEVINS: Mr. Chairman.

CHAIRPERSON DESMOND: Yes.

EXECUTIVE DIRECTOR BLEVINS: I just wanted to ask a point on the agenda.

CHAIRPERSON DESMOND: Please.

EXECUTIVE DIRECTOR BLEVINS: I think we're also supposed to hear from the ISO and EOB relative to --

CHAIRPERSON DESMOND: That is correct, and I had a request to reverse the order slightly to allow Mr. King to proceed; and then we'll hear from Mr. Saltmarsh and Mr. Mansour. Yes.

MR. KING: Okay, let me continue. The demand -- I believe demand response can and should play a significant role in the wholesale electricity markets. It really adds a dimension of, you know, another dimension of participation in those markets.

In California the Cal-ISO has played a demand response role in the past by offering demand response to participate in some of the ancillary service markets. I look forward to demand response playing an even greater role in the future, particularly after we get the MRTU program in place.

From my experience in New York demand response plays an important role in both managing system emergencies, resource adequacy, as well as being fully integrated with the market, itself.

Several of the programs that are currently in place in New York include special case resources, and this is where demand response providers actually provide ICAP, capacity to load-serving entities. And are actually an important part of their portfolios.

There's a day-ahead demand response program; and this is a market-based program where demand response resource is actually bid into the ISO's day-ahead market. They are paid the day-ahead of price, if selected. And in some cases, can actually set the day-ahead price.

The last program is the emergency demand response program. And this is the more widely used program. It's reliability based. And it plays an important role in allowing New York to manage system emergencies and scarcity conditions.

One important distinction between that program and the programs here in California is that when called upon those resources will set an administered price in the real-time market of $500 a megawatt. So that's an important linkage with the market.

It's important to understand that in order to effectively implement programs like these at the wholesale level, we need to have several things in place. The two settlement system that will be coming with MRTU, the forward market, real-time market, based on locational pricing, is key because this provides the transparent price signals that market participants need to make the investment decisions in order to participate in these kinds of programs.

Second, the fact that New York, as a capacity market, provides another venue for demand response to participate effectively at the wholesale level. And I know that that is currently under consideration here in California. And I think it's important that one consider the potential for demand response to participate in that type of a market.

It was clear when I came onboard at the

California ISO that a serious commitment to partner with the state agencies to align our market structure with state policy goals. In that regard I look forward to working with the CPUC, the CEC and other stakeholders to really invigorate the demand response efforts for the State of California.

Thank you.

CHAIRPERSON DESMOND: Thank you very much, Mr. King. Any questions before moving? Hearing none, Mr. Saltmarsh. And I apologize if taking that out of order was not communicated to you at the last minute. But, do you have a PowerPoint presentation, or just speaking from notes?

MR. SALTMARSH: I do not have a presentation to your staff. I had distributed to you copies of the very brief presentation I have. And if, for some strange reason, anyone in the audience or listening in wants it, I'll make sure it's available to your staff to be in the web materials.

CHAIRPERSON DESMOND: Well, we'll post it up online later just to make sure everyone has access to it.

MR. SALTMARSH: I thank you for being invited here today, President Peevey, Chairman Desmond, Secretary McPeak, Acting Secretary Skopec and distinguished Commissioners.

The Electricity Oversight Board has a much narrower set of missions than either of the Commissions do in energy. And so I wanted to spend my first moments identifying those areas in which the Electricity Oversight Board does work that are relevant to the goals of the Energy Action Plan.

The Electricity Oversight Board's principal missions are to monitor and investigate matters in wholesale electricity and to some extent, natural gas markets, to insure that the structures and behavior in those markets are reasonably serving the consumer public interests of Californians. To oversee the Independent System Operator in its operations and its corporate activities and in the tariffs and market structures that are part of the California ISO.

The California ISO is, of course, as you all know, a public benefit nonprofit corporation, so it would surely characterize that it works very hard to act on behalf of the public interests.

And we think we have a good cooperative relationship with them, even though we are set up as an oversight agency for them.

The Electricity Oversight Board also participates in a number of federal, particularly federal FERC proceedings on behalf of the interests of California wholesale consumers, and in advocating energy policies of the Administration of California.

The next slide page that I have addresses a question that arises sometimes with respect to the Electricity Oversight Board which is to the extent that it has a statutory mission to be a consumer advocate and to try to insure that reliability is maintained in the wholesale grid, does that mean we have too narrow a focus to be concerned about issues such as the broad range of issues of the Energy Action Plan.

And our statute does direct that wherever we are acting in reviewing California ISO tariffs, in a FERC proceeding or anywhere else, our objective is to try to obtain outcomes that are consistent with California energy policies. And we interpret that as being the entire range of energy objectives that are reflected at least in the Governor's promulgated energy policy to the Legislature. And very respective of the needs that are identified by California state agencies, particularly the PUC in carrying out their retail regulatory mandate for whatever flexibility or to accommodate whatever retail policies the PUC has in place.

So we try to insure that we would not advocate on behalf of a wholesale market structure that's inconsistent with the direction that the PUC is intending to go with the retail market structure, for instance.

In that regard, although it isn't our purview to try to act on most of the elements of the Energy Action Plan, as an agency we are trying to do everything we can to be supportive of all of those elements in the areas in which we do work.

Just to acknowledge what we don't do in that respect, the Electricity Oversight Board currently has no significant staff work involved in energy efficiency, transportation fuels, RD&D areas, or directly related to the climate change policies. Although it is certainly the case, as I mentioned, as those policies emerge or preferred generation types, for instance, to address climate action concerns, the EOB will certainly try to make sure that all of our advocacy with respect to wholesale markets helps advance those state policy goals.

With respect to Energy Action Plan activities in which the EOB does have a significant amount of staff work going on, we are also very much engaged in efforts to reform and improve wholesale market structures serving California.

Our staff energies are primarily directed at electricity markets in both California ISO's efforts to address its centralized markets, and the more generally applicable market rules that the FERC has in place related to energy trading in the western United States, generally. Behavioral rules and rules with respect to scheduling of electric power deliveries.

The Electricity Oversight Board has also had underway since 2003 policy investigation of capacity markets. It has focused primarily on the question of whether there would be a benefit to the public of incorporating some form of organized centralized capacity market into a structure like the California ISO. Either the California ISO or some other central market operator.

This is an independent question from the question of whether utilities and their regulators, in meeting their own strategic goals, would consider purchasing a capacity product through something like a procurement proceeding.

Those questions have converged somewhat and there is a significant interaction today around the policy discussions of how much of a capacity market or forward structure to insure adequate generation development should be addressed directly to the PUC through the IOUs and their procurement planning process. And whether or not there's a worthwhile public benefit to be achieved through having some additional formalized market at the ISO or elsewhere.

We continue to work both with the ISO and with PUC, in particular, in addressing those questions. We recently put out a discussion whitepaper from one of our consultants and continue to submit comments and materials both in the direction of Folsom and the direction of San Francisco.

On the subject of electricity adequacy, reliability and infrastructure, to the extent that those issues arise, we are always trying to insure that grid operating rules and tariffs, with respect to incentives for investing in transmission, are adequately serving California's needs in terms of anticipating reliable operation of the electric grid.

Specifically, the Electricity Oversight Board has historically, although historic doesn't go back that far for the EOB, has for a number of years done annual review of the ISO transmission planning process. There are efforts underway right now to improve the organization and collaboration of transmission planning, to integrate state policymaking with ISO technical evaluation of transmission planning.

That is a little bit of a process in flux. And we work with the ISO and the PUC, in particular, in the discussions of how to streamline and how to best structure a more integrated transmission planning process.

We are also engaged as one of the entities engaged in the subject of how to structure particularly federal tariffs; but, how to structure the arrangements that are in place such that they will provide both adequate incentives and just an allowance, just a reasonable environment for forward development of electric transmission that anticipates the need to build out renewable generating resources rather than a requirement that creates a chicken-and-egg problem, that you won't be able to get any kind of a federally authorized return on transmission until the line is energized, which you obviously can't do until a generating facility is in place. So nobody wants to build transmission until the generator's already there and needs it.

And we're trying to figure out an appropriate way to get those things up and built and rate-based in anticipation of the state's adopted public needs for renewable power. But do so in a way that doesn't open the door for someone to essentially build and ratebase a line to nowhere that the public doesn't really need.

The Electricity Oversight Board works a little bit in wholesale natural gas markets, as well. EOB Staff is continuing to work with the staffs of the other agencies here in the natural gas working group and the LNG permitting working group. Again, our focus is really in looking more at the dynamic of markets than on environmental issues or safety issues related to permitting of LNG or natural gas, generally.

And we are continuing to analyze some aspects of the performance of natural gas markets, particularly as they affect electricity wholesale markets. We interact with the PUC Staff on that, generally pursuant to understandings that go back to 1999, memorandum of understanding on FERC collaboration. But we try to cooperate and work with the CPUC Staff in natural gas FERC proceedings.

CHAIRPERSON DESMOND: Thank you very much. Appreciate the overview here today. Questions from folks on the panel?

PRESIDENT PEEVEY: I just have one question. We you a -- did you participate, were you a party in the recent DWR/Sempra arbitration?

MR. SALTMARSH: The --

PRESIDENT PEEVEY: Over the contract?

MR. SALTMARSH: No. We are aware of it and we are engaged in it because it affected both the EOB, as the PUC has had a complaint against long-term contracts, that included the Sempra contract, although the status of whether we still have a complaint is up on appeal in the Ninth

Circuit right now.
We also have a --
PRESIDENT PEEVEY: No, I was talking about the arbitration.
MR. SALTMARSH: Yes. We also have a couple other actions pending against Sempra, and as a consequence there was the potential for some offset, as it relates to that. We were not directly involved in the arbitration, but we were informed of the status of it by DWR because of some overlap of the issues; the complaints have some of the same issues with respect to scheduling, the complaints against Sempra's scheduling practices.
PRESIDENT PEEVEY: Were you disappointed with the decision?
MR. SALTMARSH: I am exasperated by the relationship between California and Sempra on a number of issues, including that long-term contract. And I feel like I would prefer outcomes that were more favorable to California and less favorable to Sempra there, and a few other places right now.
PRESIDENT PEEVEY: I assume you're not -- going to just say that you were disappointed?

MR. SALTMARSH: Yes.

PRESIDENT PEEVEY: Thank you.

CHAIRPERSON DESMOND: Hearing nothing further, thank you, Mr. Saltmarsh. Mr. Mansour, did you have anything you wanted to add?

MR. MANSOUR: Yes, sir. Thank you, Mr. Chairman Desmond, President Peevey, Acting Secretary Skopec, Commissioners and ladies and gentlemen.

I was introduced to you for the first time a year ago, and here I am a year later. A few months after my taking the job, Commissioner Geesman said publicly that you cannot blame Yakout if things go wrong, he's still on his honeymoon. And I tried to get from him how long that honeymoon is and he refused to tell me. So, the risk assessment, I'm going to assume that it's over.

(Laughter.)

MR. MANSOUR: So, here I am. First of all, we are going to talk, or we already talk about a lot of things that have not been done yet. But there's a lot of things that have been done. And sure enough, one year for me, I cannot take a lot of credit for what has been done, but certainly you should.

The ISO is not a policymaking entity, as you know; we're not a public policymaking entity; we're not a regulator. But, our job is to align with public policies. It would have been impossible to align with public policies if those policies are not aligned. So, thank you for your leadership that gave us the opportunity to at least get something that's aligned with your policy. EAP-II is definitely one of those.

Our approach to the activities, even though I would not classify them one-to-one to the EAP-II, but I hope you can see that it spans the whole spectrum of what your intention is. And if not, please let us know.

Our priorities, project activities span in time over the next three years according to the three-year business plan approved by the Board of Governors of the ISO recently. That can be summarized under four categories: reliability, market innovations, infrastructure development and customer care.

I will address that under the first three. First, reliability. The first priority, as we all know, is for this summer, summer '06.

And you have listened to Mr. Tom French a presentation earlier as to how we are getting prepared for it.

In addition to the regular course of actions, the slight rise of price gap, the RCSD settlement proposal, demand response which is getting better and better all the time, and amendment 72 which requires the load-serving entities to schedule at least 95 percent of their schedules in the day-ahead until MRTU is in place, are all extra insurance for this year, that we did not have in the past.

Ladies and gentlemen, it has been quoted the number of times that the net growth in resources is lagging, lagging the growth in demand. And that's true in a net basis. But keep in mind this year about 1900 megawatt of new facility, new generation is added to the system. 1500 megawatt of old, inefficient facilities are retiring.

So the fact of the matter is there is a lot of investment. And today we have 1900 megawatt more reliable, more cost efficient than we have in the year before. And sure enough, we can mention the 400 megawatt net, but we should not underestimate the 1900.

Moreover, last year the report of FERC last year on the condition of the winter, of the last winter, shows that from 2004 to 2005 actually California led the country in terms of the amount of 2004 and 2005 -- 2005 relative to 2004, which was three times. Followed by (inaudible) region which was two times. So there's a lot to be said for what actually has happened.

We're working upgrading our operators' skill, skill sets. We are working on installing new tools to help the operators maintain the system reliability at reasonable costs. All of that will add to it.

I also want to bring to your attention something that I have mentioned last year in a negative way. I brought to your attention the notion of increasing the trend of the cost of reliability. That is running generators inefficiently just to back transmission constraints.

2004 that cost was over $1 billion. And it was the tail end of the increase. We all share a concern that that cannot continue.

Happy to tell you that the reliability

costs in 2005 was $416 million less than 2004. And we continue to focus on it this year and for further years to come.

Where did that come from? Well, it's combination of IOU focus on fixing key bottlenecks; enhancement of infrastructure; advancement in operation engineering; automation in the control room; and operational excellence reflected by the operation training and the preparedness for the summer. We're targeting additional reduction this year.

We're continue to work closely with the PUC on finalizing and implementing the resource adequacy and local reliability requirements for 2007. And President Peevey, I am told that what we have done over the last few months was a breakthrough in a bottleneck between the two entities for eight years. And that is basically who's responsible for what. I think we now came to a conclusion that there are two sets of reliability or service expectations that we follow.

One of them is that of the WECC and NERC, and we both agree that that should be followed. And we are responsible to implement that, as is; and he expect us to do so.

When it comes to the service level expectation on load pockets, beyond the WECC and NERC rules, who sets the service expectations and who implement.

The problem in the past was we know that each one have a piece, but who's responsible for the whole thing. But I think we agreed lately that when it comes to what the service expectation is beyond what is required by WECC and NERC, it is you, the agency, that should set those expectations through your processes. And when that is set for us, and you're accountable for setting whatever it is, we will implement it. And that was a breakthrough. I think our staff understand that and they're working on the implementation for 2007.

I'll switch to market innovation. MRTU remains our focus. And you know that that has a lot of advantage that again stand across a number of objectives that the EAP targeted.

In the meantime, until (inaudible) transition of tools to replace the must-offer obligation that is necessary this year, and we have already taken steps at it; and you were participants in that settlement.

Again, and I want to thank you and your staff for your sleepless night, for their sleepless night in tireless effort to get to a reasonable settlement.

It is not done yet. It's in front of FERC, but at least the settlement, itself, will provide again another mechanism for generators to be there and they know that they would be paid.

Another important project this year is developing innovative market and infrastructure mechanisms to support the participating intermittent resource program, or PIRP. We know that cost allocation is an issue; it was an issue and it's still an issue.

We target finalizing a proposal this summer and hopefully a regulatory approval early 2007, or at least the regulators look at it.

Thirdly, the infrastructure development. We have come a long way in our proactive planning approach, thanks to the collaboration efforts of the CEC, PUC and with us at the ISO. I would like to remind you that the breakthrough in aligning our efforts was the realization that we can achieve all we need by collaboration based on the existing jurisdiction of boundaries. We came to that realization.

Chairman Desmond, Commissioner Grueneich and I realized quickly that the state is in desperate need for over $10 billion of transmission infrastructure over the next five to ten years. The good news is it could be done. The bad news is we do not have a minute to spare.

I urge the two agencies to rally focus on helping putting steel in the ground with whatever we have in place in terms of our jurisdictional responsibilities.

Last week our Board of Governors approved the $120 million facilities in the PG&E footprint. And our goal is to complete the major project studies in the south, which is expected to add about $5 billion of enforcement to the grid.

A lot of work to be done, but this is a growing state and growing fast. So whatever was done was not enough. But it's something to be proud of. Thank you.

CHAIRPERSON DESMOND: Thank you very much. Questions? Thank you.

At this point we're going to move to the next item on the agenda which is an update on progress toward meeting the state's demand response goals. I would note that we are running behind schedule, so I'm going to ask that staff move quickly through the slides to allow for sufficient time on some of the policy discussion issues that they have, and see how quickly we can move through this. Mr. Kaneshiro.

MR. KANESHIRO: Good morning, Panel Members. My pleasure to be here. Yes, I will be concise. Much of this material has been presented already.

Provide, again, as you said, a status report on DR goals, as well as advanced metering infrastructure. This is a joint presentation, Mike Messenger and I will share. Mike has a separate presentation following myself.

I won't spend too much time on this slide. I think we all know what the benefits are. The current action items have already been covered.

Just some brief background. As has been mentioned by some speakers already, there are two types of demand response programs, economic programs triggered on a day-ahead basis. Programs like CPP, demand reserve partnership, demand bidding. The whole idea there is economic, just to reduce procurement costs, reduce costs for the customer, increase system load factor.

Then we have emergency or day-of programs. These programs have been around much longer. Interruptible tariffs, A/C cycling. The customer is given the trigger the day-of, and load jumps are provided within five minutes, or within an hour of the signal. And the goal there is to obviate the need to trigger rolling blackout.

The question that's been asked many times is how are we doing with these programs with respect to the demand response goals that were set by the Commission in 2002. The goal for 2005 was 3 percent of system peak demand. And I apologize for the black-and-white copies, you probably don't see it as well as what we show here in color.

This chart is showing essentially the three utilities, Edison, PG&E and San Diego, with respect to the goal, as I said, 3 percent of system peak demand. As you can see PG&E is the closest to obtaining that goal, nearly 100 percent of the goal.

What we also show in here are two ways of cutting the megawatts. You have subscribed megawatts, which essentially represents the high end or optimistic view of what these programs can produce. Basically the technically feasible greatest amount of megawatts that can be produced by the customers that are on there. Essentially assuming that everyone on a particular program is responding to the trigger, to the signal.

The expected megawatts are based on some preliminary information that we're still working our way through on 2005. How did the programs actually perform. As you can see there, you have varying degrees of performance. We're trying to understand why that happened, why customers are nominating a certain amount of megawatts, or simply not responding to the signals.

So why were the price responsive demand response goals not met in 2005? Obviously lower than expected voluntary customer participation. For example, one of the programs, CPP rates for large customers, go back to this slide here. If you look at, for example, Southern California Edison. As you can see there really isn't any CPP megawatts there either subscribed or expected. So it's very low. They do have some customers there, but it's so small it doesn't show up as a percentage in this graph. I believe there's eight customers currently on Edison's CPP.

So we have much lower than expected voluntary customer participation. Part of that is perception by large customers that the benefits of demand response programs and the tariffs do not offset the cost for them to participate.

Another barrier is the sticker, what we call sticker-shock effect for customers that as these programs have been rolled out, as they've been marketed, the focus has been on the high CPP peak rate that they would be paying. But not of the discount that they would be receiving on onpeak usage for the remainder of the summer. So, obviously more customer education, better marketing could be used to address this problem.

Then in 2005, early 2005, the Commission started to express doubt that we could perhaps achieve these goals through voluntary measures. So the Commission opened a proceeding to explore default CPP, essentially placing largest customers on CPP rate and giving them the opportunity to opt out perhaps after a year; allowing them the opportunity to basically experience the program with some bill protection.

And the response has been that large customers are very resistant to default CPP. That they believe that rates such as these are unfair and punitive.

And then lastly, demand response is only being generated by the large customers, those who are over 200 kW. So we're not receiving, at this point, any DR from smaller commercial and residential customers because they don't have the AMI meters in place to participate in these programs.

So, essentially there's one customer class providing all of the demand response. That's another reason why we haven't hit our goals.

We put this slide in just to give you, I guess, a comparison or way of comparing how we are doing with respect to the emergency or day-of demand response, again compared to that same goal of 3 percent of system peak demand. Obviously Southern California Edison has twice the amount of that goal, about 1000 megawatts. And you can see PG&E and San Diego again, the subscribed and expected are shown there, as well.

And the reason that they're much closer, the subscribed numbers and expected, is we have much more history with these programs that's shown to be fairly reliable in terms of when they're called. Customers do respond, and thus there's very little difference between that subscribed and expected number.

And I'm going to turn to Mike Messenger to give you the update on the advanced metering infrastructure.

MR. MESSENGER: Hi. I'm going to try to follow Joe's dictum and talk really fast. If I talk too fast just let me know, raise your hand.

I'm just going to highlight the status issues, and I'm not going to go into the key issues now unless someone would like to raise that as a question.

Basically PG&E is the farthest ahead of the investor-owned utilities. They are already pre-deploying interval meters in Vacaville, and there's going to be a draft CPUC decision in June, and hopefully a final decision in July.

San Diego is right now engaged in system testing, and they're trying to select a vendor for who's going to actually install the system. They hope to do this in the second quarter of 2007.

There's a supplemental filing that provides details of the costs and benefits of that. The draft decision from the PUC should be around in November of 2006.

SDG&E believes it will take them 2.5 years to roll out to their entire service territory if they start in mid 2008.

For SCE they're taking a more studied approach. They want to make sure that when they install a system it gets all of the latest technologies in and provides a lot more functionality than the current set of AMI systems. So they're involved in system design and technology evaluation right now for the next 18 months.

In phase two they're going to prepare their business case; and hopefully file it by December 2008. They might actually file it earlier; it depends on how quickly their business case goes.

Just added this slide because we're also trying to keep track of what's happening with AMI of the major municipal utilities. Just talked with a gentleman from SMUD this morning. They are preparing to install five-minute interval meters for all of their customers. There's a 60,000 meter phase one project where there's already installing meters underway. And they say full implementation may begin starting January 1, 2007.

Anaheim has also been pioneering efforts to get advanced meters to the residential customers. They had a meter pilot in 2005/2006. They're moving ahead with the two vendors that were selected as a result of this pilot. And they hope to complete their business case within the next few months by August 2006. The vision is to deploy meters to all customers over the next five years.

Now, I'm going to take you back to Bruce.

MR. KANESHIRO: Just wanted to highlight the key proceedings that would affect DR going forward. The first three have already been mentioned by the Executive Directors in their presentation.

The fourth bullet point, I believe Mike is going to cover in his solo presentation. The last one, just resource adequacy. Demand response does count in resource adequacy rules currently. But my understanding is that there are concerns about the performance of demand response. Is it a reliable resource.

So, it's upon demand response proceeding to provide more accuracy, better understanding of this resource as it continues to progress forward. And how it will be treated in resource adequacy would then obviously affect our ability to obtain more demand response in the future.

Then lastly, again, as we said, there's demand response goals have been in place since 2003. The goal will keep ratcheting up as each year goes by, so 2006 I don't have that on the slide, but it's 4 percent of system peak demand; 2007 it goes up to 5 percent of system peak demand.

And the question is, is it time to take a step back and reevaluate these goals and how we're setting them. Obviously there's decisions going forward right now in the current proceedings that would affect that. So staff is thinking of redoing them or relooking at them, the winter of 2006.

Some possible options that have been thrown out by parties in the proceeding are setting separate goals for customer classes, or setting separate goals for the types of demand response programs.

And that concludes the first part of this presentation. Any questions?

CHAIRPERSON DESMOND: Thank you, I appreciate your going through it so succinctly. Questions here on the panel?

I do have a question. If you don't mind going back to slide number 6. And I'm going to hold off the policy discussion until we hear from Mr. Messenger in the next, but your slide 6 here. And I just want to make sure I'm reading this correctly.

The goal is for 2005, but I just want to point out a couple things, because I think we're in a more precarious position than we realize with respect to the demand response goals.

The yellow category, which is the DRP expires in May of '07, is that correct, so this is the last summer we'll have that as a resource.

MR. KANESHIRO: Yes, that program does end. But the utilities have been directed to come up with a replacement program. And they will be submitting their proposals this summer for that. So we would hopefully have it in place by May '07, a new program to replace essentially the DRP.

CHAIRPERSON DESMOND: Okay, but roughly 90 percent of that comes from the State Water Project's participation, and I just want to make sure that we recognize where the concern is in going forward.

The second is that goal goes up next year to 4 percent. Actually this summer it's 4 percent, 5 percent in '07. So we're actually falling further and further behind than the graph necessarily might illustrate.

And, again, I just want to make sure, the concern here is we need to be focusing some energy and effort on making sure we get back on track. Because we are falling further behind. And with some of these things expiring, raises certain types of questions.

So, I'm not being critical here; I'm just pointing out that the slide doesn't necessarily tell the whole story here.

MR. KANESHIRO: This is just a snapshot in time, and you're right, that DRP is, most of that megawatts is one customer in PG&E's service territory.

CHAIRPERSON DESMOND: Thank you. Okay,

next presentation.

MR. MESSENGER: Okay, now in light of that last slide and the fact that we need to try to move forward, we're going to be presenting some policies to try to move greater levels of price responsive demand into the sector. And I just want to thank you, again, for inviting both Bruce and I to talk about this, because we think it's an important question for all of Californians to consider.

First, Art wanted me to make sure I gave a Title 24 briefing update about programmable communicating thermostats. I'll do that, and then I'll talk about three policies to increase the level of price-based response way beyond what we've seen so far the first three years of the program.

So in terms of the update we've been analyzing this for roughly six months. We've established that there's a considerable potential to provide immediate and geographic-specific load drops on an emergency day for all new homes -- and that should be HVAC as opposed to HBAC -- retrofits during emergencies.

We estimated roughly 400,000 homes per

year will be installing these PCTs once the code goes into effect. And it will give the utilities and the ISO potentially the ability to target demand reductions immediately. And when I say immediately, within like five minutes, for all new homes. So we think that's a very good thing.

Of course, what's needed also in addition to the PCTs is the AMI, the meters to go along with that, particularly for economic reasons.

We've also hired a consultant who has published proof of concept PCT including the material and fabrication costs which are quite reasonable, on the order of $60 retail. And functional specifications have been developed for these new programmable communicating thermostats that will support either one- or two-way systems.

The two-way system is being supported by essentially that little USB port that will allow people who want to establish two-way communication systems to put it in in the future; whereas, we'll have a one-way broadcast network from the beginning.

And finally, the preliminary analysis has shown that PCTs are, in fact, cost effective for all climate zones, assuming that CPP is at default rate. And for most climate zones, if we assume that CPP is adopted as a voluntary rate for residential and small commercial customers.

So what are the three policy recommendations that we'd like you to consider today? The first one, I think, is sort of ongoing. We'd like you to reiterate continued support for installation of AMI systems with the functionality to support dynamic rates for all California utilities.

The second one is we would like you to consider developing some kind of performance based incentive system to encourage GR goal attainment by 2008. We do that in part because when we set energy efficiency goals and set up performance based systems we noticed that we got quite a lot and people were exceeding their goals. So we should at least look into this for DR, as opposed to just having the goals set out there by a regulator and reviewed occasionally.

And finally, policy number three, we think we would like to get your support for the use of CPP, critical peak pricing rates, as the default rate for residential and small commercial customers, with the opportunity for all these customers to opt out to either TOU or current rates after a trial period.

So now I'm going to provide some of the rationale for these three policies.

First one, continuous support of AMI system deployment. We think that there's really a renaissance taking place nationwide. There's burgeoning interest really everywhere we go in AMI after successes in both Pennsylvania and Wisconsin in installing them. And initially in California.

We think that when people actually compute or calculate the business cases, is it, you know, benefits exceed cost. They've been positive so far for most utilities in California. And there's an opportunity, perhaps a historic one, to piggyback with the installation of water meters, particularly in the Central Valley.

If you're going to be installing metering systems you can reduce the cost if you can install metering systems that provide back both electricity, water and gas readings at the same time.

And I think in particular some of the municipal utilities in the Central Valley have some historic opportunities to work that, because water meters are now required in most of California.

Finally, we think there's additional operational benefits and value that will come from installing AMI in terms of supporting the California solar initiative. Primarily because it's very important to monitor the actual production of these solar facilities, whatever they are. And particularly if people want to, as the PUC said earlier, consider performance based incentives, it will be essential that you have some sort of AMI support.

Now I'm on to policy number two, a rationale for development of some kind of performance based mechanism to achieve DR goals at the utility level.

We suggest that if you decide to go ahead with this, the system should compensate utilities for any measured reduction in procurement costs, any measured increase in system load factor, and/or simply meeting the DR goals within some percentage deadband.

And the costs and penalties all need to be, you know, litigated in a proceeding. But we think it's important to move ahead with that if you can.

And we would ask you to consider the share-the-savings model that was used in EE proceedings in the 1990s. And we think it's consistent with the recent OIR from Judge Gottstein on this topic.

Finally, policy number three. We think it's important that we make additional progress in the demand response field by making critical peak pricing the default rate for small commercial and residential customers. And I'm going to present probably three slides explaining why and try to go fast here because I know you want to talk about this rather than listen to me.

First, over two-thirds of the customer on our pricing pilot both saved money and supported the use of default -- CPP as the default rate in the post-pilot surveys. And this graph shows that just in terms of the bill analysis. 73 percent of the customers had lower bills who participated in this in the first year. And 84 percent in the second year. So they continued to reinforce and learn how to save on their bills with the receipt of this rate.

There's almost no change in the commercial, that second set of bars there, between 2004/2005. Roughly 80 percent of the people are saving money.

Finally, and I think this was perhaps the most surprising finding for me, when we talked to the people after they had experienced this dynamic rate for 18 months, we first asked the question should dynamic rates be offered to all customers. And as you can see, anywhere between 87 and 91 percent of the survey said either definitely or probably. Those are the different ones, the blue and the green there.

And then when we asked them in the second column over there, should all customers be placed on a dynamic rate, and then given the opportunity to switch or opt out, again, surprising pluralities, from my perspective, anywhere between 63 and 67 percent said either definitely or probably.

And that was independent of whether they were on the time-of-use rate, a CPP rate, a CPP variable rate, which means it could be a two-hour or five-hour dispatch, or surprisingly enough, for the people who only got information and were not even on the CPP rate, itself, they said this makes sense to us. So we think there's lots of public support for this policy.

This is just a graphical showing of what happens in a typical house. And it shows the difference between what the houses did on a control group in terms of what their peak load was, that's the blue. What houses that were on a controllable thermostat with a flat rate and rewards, they were paid, you know, a certain number if they promised to do their reduction. And then the last slide is if you add enabling technology which allows this to happen automatically. There's a signal sent; the controllable thermostat sets the thermostat up between two and four degrees; and that's the orange bar that you see there.

A significant amount of rate reduction. In this graph about 2 kilowatts. And this is a house with air conditioners in a hot day. You know, this is an extreme condition. But this is when you need it, when you have extreme conditions in California.

Some other reasons why we think it's important to make CPP the default rate. First, you will dramatically increase the fraction of customers who are on the rate. Our market research suggests that if you opt for volunteer you're going to get a 10 to 15 percent opt-in rate within two to three years. Versus if you make it mandatory with opt out, you're going to have 60 to 75 percent of the people staying with CPP rates.

So if you just do the math you're going to have an increase of the megawatts achieved by probably a factor of four. It was estimated to be up to 2000 megawatts in the CRA report.

Finally, at the end of the pilot, when all these 1000 or 2000 customers were through, and they were asked, well, what do you want to do, they said we would like to stay on our CPP rates. We don't want to go back to our old rates. After they had time. And we think this is important because it's important for all customers to receive these set price signals and then decide for themselves whether they want to stay on and make money or they can opt out to their old rate.

This is just a summary of again what the reasons are to stay with CPP rates. I want to point out the disadvantage of a voluntary CPP rate is you get lower overall rates of participation.

And, most importantly, all the structural winners or free-riders, people who would save money without making any peak reduction whatsoever are the people who tend to join. Because they say, hey, this is a no-brainer for me. My current load shape gives me reduction in my monthly bill without doing anything. So those are the kinds of people that tend to predominate in a voluntary program.

So, finally, a summary again of our recommendations. I've said them enough times so I'm not going to spend a lot of time on policies one and two.

On number three I want to say that I think there's three options that you should consider, and we should work together as a team to figure out which is the right one.

We could either have a policy of directing all utilities to file time-differentiated rates as the default in the next rate design proceeding, including the current PG&E proceeding, which is happening right now, for all customer classes.

Or we could use this rebuttable presumption approach which is making the CPP rate the rebuttable -- this presumption, sorry, in all rate design proceedings unless or until parties make a strong showing that the time-differentiated rates are not fair or reasonable compared to the current rates.

And/or the other thing we could consider is asking staff to work with a willing utility to jointly develop a set of default rates that both parties can support, and then file those in a rate case.

So, thank you for your time and questions, and I'm open to any questions from the audience or the dais. Thank you.

CHAIRPERSON DESMOND: Thank you very much, Mike. Commissioner Rosenfeld, would you like to start this off?

COMMISSIONER ROSENFELD: Only to support what Mike said. I do want to make it clear that these proposals are the consensus of an ad hoc demand response committee including Commissioner Pfannenstiel, who's not here, and me and our staffs, which meet every Thursday. It has not been discussed with the whole of the Commission. But I would open it up for questions.

CHAIRPERSON DESMOND: Okay. I'd like

just a clarification, Mike. When you went through your presentation on slide 7 the headline was, policy recommendations for consideration; make CPP default rate for small commercial and residential.

And then you presented information in support of that on slide 9, slide 8 -- slide 9. But the summary recommendation says, make the default for all classes.

And my question is you also presented earlier information about sort of the resistance from large commercial customers. And I'm wondering, is that just a typo, or are you saying in the face of that other evidence we're still suggesting we make it the default for all. Or just the residential and small?

MR. MESSENGER: First of all, let me apologize. The reason that it's inconsistent is we went back and forth with our colleagues from the CPUC. And at the last minute we decided not to press forward with sort of let's call it a compromise, and just present this as a CEC Staff position. So, that's what I'm doing.

It's the CEC Staff's position that it should be all. That we should have a CPP default rate for all, even in light of the controversy that we've seen so far in the industrial --

CHAIRPERSON DESMOND: Okay, and what is the CPUC Staff position on that?

MR. MESSENGER: I'm not going to speak for them, so I'm going to let them talk --

CHAIRPERSON DESMOND: Okay, thank you.

MR. GALLAGHER: The PUC Staff's position is that we ought to adopt the time-differentiated rates as the default rates for all customers, particularly once we get the meters installed for the smaller customers. You know, currently only the large customers have the meters installed that would support these time-differentiated rates.

What the PUC Staff hasn't firmly adopted as a position yet is whether those time-differentiated rates should be some form of CPP rates, some form of TOU rates, some form of real-time pricing or something else.

And we do hope to address those issues shortly.

CHAIRPERSON DESMOND: Thank you for the clarification, Sean. Obviously I think, just as a general comment, we pay time-differentiated rates for many of the products we buy every day, whether that's airline tickets or hotels or cellphone usage on nights and weekends. So this is not a new concept.

But the state has invested considerable time and money into investigating this, I think almost $10 million in the two-year statewide pricing pilot. And we've had Roger Levy up here before walk us through all the details and the responsiveness of that.

So, I guess questions from folks here. Commissioner Geesman.

COMMISSIONER GEESMAN: I'd add to your cost tally the $31 million the general fund spent several years ago installing meters at the large customers.

CHAIRPERSON DESMOND: Just a question, Mike. On the current analysis that was done, was that done on the tariff design? And is the recommendation to modify the tariff as it was implemented last year? Because I believe it was done on a class revenue neutral basis, not a customer revenue neutral basis.

And this is one of those subjects where unfortunately the devil's in the details. And we really need to make sure we're getting it right. So I'm just trying to get a sense of what the specifics of the proposal are. I've got a clear idea of what the CEC Staff recommendation is on the policy side. But are you satisfied the current tariff design is the appropriate one? Or that the PUC has raised the staff questions regarding how the tariff, itself, needs to be designed?

MR. MESSENGER: I think it's clear that both members of the joint staff feel that the current round of tariffs that are currently in front of the PUC in terms of a settlement have some flaws in them.

And so we are not necessarily supportive of those tariffs. But we continue to believe that the policy is correct.

And we're currently discussing with our colleagues at the CPUC what's the best way strategically to get through this vote of the Bowen alternative versus the original default policy, which was abrogated by the settling parties.

So, it's a strategy call as to how to get there. Our advice would be right now, at least at the staff level, is not to adopt the rates as filed in the settlement, because we think they have some real revenue requirement problems.

And that's why we have this proposal up here to make it a rebuttable presumption in rate designs. Because theoretically that's the best place to put these things is in the rate design. Because then when all the tradeoffs are made between different rates, you can do it there.

CHAIRPERSON DESMOND: Okay. We had a workshop, I think it was on the 9th of April, and I just want to call attention. This was an alternative Title 24 compliance for the use of ice storage systems that could be used to shift peak. And I don't want to lose sight of the need to design tariffs to support permanent load shifting, which would be the -- we talked about the ice storage, Commissioner Rosenfeld, in fact, I think it's up again on a business meeting, something the Energy Commission has been supporting through its R&D efforts for some time.

So, in the discussion or in the recommendations has there been some examination or exploration of also considering permanent, meaning to create and capture the value of year-round load shifting, instead of -- I shouldn't say instead of, but rather in addition to critical peak days?

COMMISSIONER ROSENFELD: Commissioner Desmond, you know this, but I'm going to say it anyway.

CHAIRPERSON DESMOND: Yes.

COMMISSIONER ROSENFELD: The critical peak tariff which we favor is critical peak only maybe five hours an afternoon for say cool summer four times, really hot summer 10 or 15 times. Where we believe that people are willing to accept discomfort when there's really a crisis.

But there will be time-of-use every afternoon. So we're moving as much as we can in the direction of tariffs which reflect costs.

And then there should, of course, be a renaissance of things like thermal storage. So, I repeat, we're in favor -- we were very happy for residential and small commercial people who don't have the meters yet, with the results of this $10 million statewide pilot program. People liked it; people saved money; and they did have time-of-use every afternoon.

CHAIRPERSON DESMOND: Okay, thank you. Again, I was raising the issue, Commissioner, only in support of expanding and achieving a greater level of demand responsiveness in the state, given that we are falling behind our goals. So, I am aware of that, thank you.

Commissioner Geesman, and then Commissioner Rachelle.

COMMISSIONER GEESMAN: I'm not certain if this is a question for Mike or for Art, but in terms of --

CHAIRPERSON DESMOND: Excuse me --

COMMISSIONER GEESMAN: -- in terms of the thermostats that you mentioned, programmable thermostats being considered for Title 24 standards, is Title 24 the best vehicle for that? Or are our load management standards, which would apply to the existing housing stock and also apply to municipal utilities a better vehicle?

MR. MESSENGER: Art, do you want to take that, or do you want me to try first?

COMMISSIONER ROSENFELD: Go ahead, Mike.

MR. MESSENGER: I think we've concluded that in order to transform this market we need to have a successful demonstration with new construction first. And work with the thermostat vendors at the place where it's relatively cheap to install new thermostats, like during the new construction phase.

And then our anticipation is that we will, in fact, ask for load management standards one or two years after that, so that we can expand it to the existing classes.

The manufacturers we've been working with have agreed with that approach. And if it's really successful they believe that there will be enough word of mouth that people will go to Home Depot, buy one for $40, and retrofit it. So they can do that.

COMMISSIONER GEESMAN: Thank you.

CHAIRPERSON DESMOND: Commissioner Chong. We didn't have a policy change to only refer to Commissioners by their first names.

COMMISSIONER CHONG: Thank you. This is for Mr. Messenger. You talked about the settlement earlier, and you thought there were some issues relating to revenue requirements. Could you just speak for a minute about that problem so I can understand it better?

MR. MESSENGER: I can, although I should say David Hungerford is the expert. And he's not here, so I'll do my best. There he is.

CHAIRPERSON DESMOND: Is he leaving?

COMMISSIONER CHONG: Yeah, he's fleeing

the room, Mr. Messenger.

(Laughter.)

MR. MESSENGER: My basic understanding, the question is when you set CPP rates, do you set a revenue requirement that's fixed that requires you to call CPP for a certain number of times every summer? Or do you say, hey, some summers are going to be cool, we'll only need to call it three times. And we don't need to call it extra times just to make up the revenue requirement.

We had asked the utilities to be flexible and have it a flexible revenue requirement so you might actually get less money that summer because you didn't call it that many times.

The utilities, in my judgment, filed uniformly no, we need to recover our revenue requirement; we're going to mandate a minimum numbers of CPP have to be called. And we think that doesn't make sense. We think you should have a balancing account.

COMMISSIONER ROSENFELD: Could I add to that. Mike just said, I think, the magic words. Mike and I, at least our Committee, feels it's stupid to try to balance out every year when the

weather goes by ten-year cycles. So we want a
ten-year balancing account.
And now I'm sorry to repeat something,
but we think it's very important that if we're
buying discomfort from people it should be at a
time when it's uncomfortably hot and the system is
really challenged. And we just can't see this
one-year closure.
CHAIRPERSON DESMOND: Mr. Hungerford.
MR. HUNGERFORD: There are a couple of
other issues beyond the settlement requirement --
COMMISSIONER ROSENFELD: David, louder.
MR. HUNGERFORD: There are a couple of
other issues with these rate designs that were
part of the utility filings last August, and that
were accepted in the settlement agreement beyond
the revenue requirements.
One of them is that there's a variety of
different ways that the revenue collected during
the CPP period is reallocated -- is allocated back
to the customer, the way the discounts work.
One of the policy goals that we've had
all along with moving a CPP rate design forward is
the idea of encouraging permanent load shifting
out of the peak. And the way at least one of the

CPP rate designs that was put forward by one of the IOUs was designed, it would reallocate the revenue into the peak period on other non-CPP days during the summer. Which, from a customer perspective, balances the costs a little better. And so was probably the genesis of that particular design. But it doesn't promote the other goal of conservation, permanent conservation on peak.

And there are a number of minor issues, most fundamentally the number of calls that were expected per year for each of the rates. And the utilities, all three, handled them a little bit differently.

And so the problems with these rate designs have to do with a statewide uniformity; of course, recognizing the unique differences between the service territories and with the revenue requirement and with the particular incentives inherent in the designs.

And so there are some fundamental problems that need to be worked through. And were not allowed to be worked through in the litigation process, because the proceeding was cut short by the settlement.

CHAIRPERSON DESMOND: Thank you.

Commissioner Bohn.

COMMISSIONER BOHN: Just one quick question. Forgive me if you all covered this before. My sense is that there are some users who, no matter what you charge them, simply can't shift. Did you look at that? And how does that relate to this process?

The purpose of this exercise presumably is not just to charge people a lot of money, but to change behavior. If you can't change behavior on some of these, then being punitive is kind of an interesting exercise, but doesn't get to the point.

Did you look at this? And, if so, where does that fit in the overall kind of space we're talking about?

MR. MESSENGER: Thank you for your question. The first thing I'd say is whenever you change rate designs you create winners and losers automatically. There are some people who have been paying less than they should have because they haven't been charged the full cost of delivery. And there are other people who have been paying more, perhaps, than they should have.

And so I do believe that there are a set of industrial customers who would have difficulty adjusting to this CPP rate without paying higher bills. I think that's a small percentage, but I think they would have difficulty.

Our perception has been this is not a program where we try to make the rates good for everybody. This is a rate where we try to charge the true cost of delivering electricity and let things fall as they may. And it may be that there are some customers who have, let's say, a majority of their load during the peak period that would pay slightly higher -- our estimates are on the order of 5 to 10 percent -- for particular bills in particular months.

But we think it's the right thing to do to send the right price signals first. And then let people buy the necessary equipment to adapt on a secondary basis.

So, you're right, there are some, but we think the majority would be better off.

COMMISSIONER ROSENFELD: But -- emphasize, this is an opt-out possibility. No one has to stay on this tariff if he doesn't want to, to repeat Mike's words. Mike wants people to be exposed to the experiment, see if they can save money. But if they don't save money, they will get a shadow bill every month.

We could even fix it so that they -- well, let's just say they'll get a shadow bill every month. And after the end of some reasonable period they can opt out.

MR. MESSENGER: That's the other thing I should have said -- I'm sorry, Art.

COMMISSIONER ROSENFELD: Go ahead, Mike.

MR. MESSENGER: The other thing I should have said is for those customers who physically can't, because let's say they have an automated production facility that has to run during those hours, they can opt out. So it's as simple as that. They experience this rate for two or three months, and they say, look, two or three months, can't do it, I want to opt out. And that's fine.

CHAIRPERSON DESMOND: Commissioner Chong.

COMMISSIONER CHONG: What kind of minimum period would you recommend, though, for this trial period? It shouldn't be just a month. It should be maybe three months, six months?

MR. MESSENGER: David points out to me that most people point out one year. There's some debate about three months versus one year. I would say that to be fair to the customer, since the rates are much lower in nine months of the year, you'd want to have it for a full year so they could see the savings in addition to their exposure to potential additional costs in the summer.

Because the thing that I keep emphasizing to people is you don't sell this rate on a high rate that's going to happen 1 percent of the year. You sell it on the 20 percent discount you get for the 90 percent of the year that's outside of the summer. And most industrial customers see that and can understand that when they make their rate calculation.

CHAIRPERSON DESMOND: President Peevey.

PRESIDENT PEEVEY: Well, I was just going to say that spending some time on this, believe me, with Commissioner Rosenfeld, with the Energy Commission, myself and Secretary McPeak, who's not here, but it wasn't long after I went on the PUC that Rosenfeld got on my case, as did Ms. McPeak, about looking at both AMI and CPP, and some variant thereof.

And we've done these pilot programs and

everything else. My personal opinion is that the evidence is overwhelming that this is the right direction for public policy in the State of California.

There are, as Art explained, there are opt-out provisions to take the seasonal canner and this kind of thing into consideration.

But for the vast majority of industry it seems to me that we want industry in this with a default provision, which they can exercise. Because they are the most sophisticated knowing how to move their load around.

But we also want ultimately residential and smaller commercial in this, too. And the reason we did spend years on this and did pilot projects and all this was to demonstrate clearly that when people fully understood their bills and how they were put together and what the advantages were to them, they overwhelmingly opted for these kind of programs.

And that was not taken lightly. The scores of millions that we spent on this program, and which for some advocates delayed its inception, but I think we were well grounded in so doing.

And the differences between, I think, the energy division and the Energy Commission here are in details, not in policy thrust.

CHAIRPERSON DESMOND: Thank you, President Peevey. I'd like to acknowledge and welcome Commissioner Grueneich who has joined us.

COMMISSIONER GRUENEICH: I was going to say, contrary to what people are thinking, I did not walk from Davis here. But, where is Director Larson with our train regulation? I promptly was on the train in the East Bay at 8:00 a.m. this morning. And we sat outside the tracks at Davis for two and a half hours because unfortunately there was a death on the track.

So, my apologies, but when one takes mass transit you're a bit of a captive.

(Parties speaking simultaneously.)

COMMISSIONER GRUENEICH: Actually, but I did have the wonders of technology by being able to, on my laptop, access the webcast on the video and audio. So I was going to say to Commissioner Geesman what I really was doing was as soon as I heard your opening remarks on our failure on the RPS was to get off the train and go out and find some projects and get them going.

(Laughter.)

PRESIDENT PEEVEY: Was there any -- the body, was that someone coming to the meeting here?

(Laughter.)

CHAIRPERSON DESMOND: Thank you. Any further discussion? Commissioner Chong.

COMMISSIONER CHONG: I'm the assigned Commissioner on the 2007 PG&E rate design case. And I just wanted to say that I do intend to tackle demand response tariff design there, along with critical peak pricing.

CHAIRPERSON DESMOND: Thank you. And thank you, staff, both the CEC and the PUC, for putting this information together.

Moving along, then. Agenda item number 5, and just as a reminder while we're getting set up, we have blue cards in the back. We are scheduled to go to 1:00. Depending on how quickly we go, may go to 1:15, but I'd like to do this rather than have to break for an hour and then come back late in the afternoon.

So, again, I will simply ask that the next presenter step through the information. Mr. Gallagher, welcome.

MR. GALLAGHER: Good morning, again.

Thank you. My report is on resource adequacy and long-term procurement planning. I will attempt to go through this quickly in the interest of time, so I may skip some of the information on some of these slides.

What I'll give is the overall summary of the presentation is that in December when we were before you we indicated that we had a couple of key initiatives we were going to commence, resource adequacy and long-term procurement, with goals to have decisions issued in June of this year.

We have commenced both of those initiatives and we are making progress towards those June decisions. The one is adoption of local resource adequacy requirements. And the second is consideration of policies to facilitate the investment in new generation in California.

This slide just shows some of the key milestones in resource adequacy and long-term procurement. And, again, I direct your attention just to the bottom portion of the slide, the first round of system resource adequacy compliance is underway. And we have opened the two new proceedings, one to consider local RAR and the second to consider the long-term procurement plans, including investment in new generation.

We did adopt resource adequacy rules in October of last year, and the first year-ahead filings were made in this February. The showing required was that the load-serving entities had locked up at least 90 percent of the resource adequacy requirement for this coming summer. And then they have to start filing, making monthly filings in May of this year.

Just a quick report on what those year-ahead filings showed. Those February filings indicated that 99 to 116 percent of the need was met either by ownership or contract. You can see what the monthly numbers are there in the third bullet. So that is the -- all the load-serving entities, the overall showing was in excess of the 90 percent of the need that was required.

And we show on here there is a fair amount of liquidated damages contracts that will count in 2006. That number drops off fairly steeply in 2007. And it goes almost away in the years after 2007.

In December the Commission did adopt the new follow-on resource adequacy proceeding. The principal phase one issue is the adoption of the local resource adequacy requirement that will be based on the ISO's local capacity requirement study.

Other issues were trying to tackle in the phase one process is implementation and compliance. And then we're also trying to address the further refining of the tradeable capacity product that would count towards resource adequacy. The parties have been doing most of the work on this, and we're hoping that they're going to bring us something that we can consider for the June decision.

In phase two that we'll take up after we get out the phase one decision we're going to look at capacity markets and further look at the tradeable capacity product issue. We're going to look at moving the resource adequacy requirement out further, more than the current year-ahead requirement.

We're going to take a look at whether we need to adopt a zonal resource adequacy requirement to supplement the system requirement we currently have and the local requirement that we'll have this summer. And then we'll look at other implementation issues. And we're going to try to adopt what we're calling a resource adequacy general order that would sort of roll all the requirements into a single place for ease of reference.

Local resource adequacy is under way. There's a lot of information on this slide, but I'll direct your attention to the second-to-last bullet. The ISO did issue its local capacity report last Friday. This was a critical path item in adopting local resource adequacy standards by June. And so the ISO did meet its commitment to issue the study, and so we're on our way there.

The second key initiative that we adopted since we last met in December was the adoption of a new long-term procurement plan proceeding. The principal phase one issue is the need for additional policies to support new generation. And we're still planning for a June decision on that.

The phase two issues for the long-term procurement plan proceeding will be the review of long-term procurement plans, including long-term procurement policies such as credit policies. And we're going to take a look at whether there are currently barriers to the participation in long-term procurement solicitations that are making the response solicitations less than they could be.

The decision on the long-term plans in those policies is anticipated to be around the end of this year.

One item that was highlighted by Commissioner Geesman earlier is PG&E has announced recently the results of its RFO for new procurement. They commenced about a year ago. At this point they've announced seven contracts; five are purchases of energy; two would be term key projects the utility would ultimately own. 2200 megawatts would be online in 2009 and '10.

There's about 1200 megawatts of combined cycle technology. About 700 megawatts of combustion turbine technology. And then there's about 279 megawatts of reciprocating engine technology, which is sort of a load-following technology. We can talk a little bit more about that if there's interest. PG&E will be coming to us shortly with requests to approve these contracts.

Other information is on our website. We've got the URL here and the slides are on the

Energy Commission website. So if anybody's interested in further detail on this, that's where to find it.

CHAIRPERSON DESMOND: Thank you very much, Mr. Gallagher. Questions? Okay.

All right, at this time, then, I'd like to move into the public comment section of this meeting. First up we have Mr. Steve Brink from California Forestry Association. Behind him would be Brian Theaker, Regional Government Affairs Manager for Williams Power.

MR. BRINK: Good afternoon and thank you very much --

CHAIRPERSON DESMOND: Green light should come on.

MR. BRINK: Oh, green light.

CHAIRPERSON DESMOND: Thanks.

MR. BRINK: Good afternoon. My name is Steve Brink; I'm the Vice President of Public Resources for the California Forestry Association. I represent much of the remaining forest products industry in California, and some of the biomass power plant industry, as well.

My comments today are focused on just the biomass particulars, getting to 20 percent renewables. As I suspect you know, in the early 1990s there were 49 operating biomass power plants that produced over 800 megawatts. Today there are only 28 that produce 550 megawatts, just slightly less than 2 percent of the renewables portfolio.

To get to 20 percent the CEC bioenergy action plan included two priority items related to biomass, the industry and the power plants. One, obviously maintain the existing infrastructure. And two, create a business climate so we can have 1500 megawatts of new installed capacity, which would be a 5 percent increase from biomass to the renewables portfolio.

Now, obviously there's two parts to the equation. The price that's paid for the electricity and the abundance and reliability of the fuel, the biomass that has to flow to the power plants.

Regarding price, I would remind both Commissions that the recent Western Governors Association task force report reported that social benefit of biomass-generated electricity is at least 11 cents a kilowatt.

The bottomline for California's biomass power plant industry is that six or seven cents is not going to do it. It's not going to be sufficient.

Regarding supply, I'll just give you one example of an additional potential in terms of supply. I'm 36 years retired Forest Service. I know the national forests in California well. They've not seen significant active management for 15 years. Active management could produce a fivefold increase in the cleaning up of our national forests here in California, making them healthy and resistant to catastrophic wildfire again and the destruction that comes with catastrophic wildfire.

The result would be 12 million green tons of additional fuel, which is almost 600 megawatts of new power. So our national forests, alone, in California could get us 40 percent of the way there in terms of the 1500 megawatts of new installed capacity. That is one of the priority items of the action plan.

In the interest of time, there's more specificity in my written comments, and a reminder that California forestry Association is always ready and willing to help either CEC or PUC make the bioenergy action items a reality. And particularly to provide a healthy business climate for the business power plant industry.

Thank you very much.

CHAIRPERSON DESMOND: Thank you very much, Mr. Brink. And I think you heard Commissioner Boyd earlier indicate that the agencies are now awaiting the Governor's Office response, detailed response to that plan. So, I'm sure you'll be hearing more.

MR. BRINK: Thank you.

CHAIRPERSON DESMOND: Thank you. Mr. Theaker. And behind him will be Scott Hawley from Watson Cogeneration.

MR. THEAKER: Chairman Desmond, thank you, President Peevey, Commissioners. In light of the fact of what has been discussed, what has not been discussed today, and the absence of the ISO contingent, I think I can help you meet your deadline by deciding to not offer public comment today. But thank you for the opportunity.

CHAIRPERSON DESMOND: Thank you. I want to make sure all that is in the record, that you commented that you wouldn't comment. So, --

MR. THEAKER: Of course, Ms. Smutny-Jones notwithstanding.

CHAIRPERSON DESMOND: All right, thank you very much. Mr. Hawley.

MR. HAWLEY: Watson Cogeneration will refer its time to Michael Alcantar.

CHAIRPERSON DESMOND: Very good. Mr. Kelly from IEP.

MR. KELLY: Thank you, Commissioners. Steven Kelly with Independent Energy Producers. I wanted to briefly follow up on some of the comments that started the meeting, and then at the end with Sean speaking about the barriers to generation development, and particularly the importance of transparency to the procurement planning process.

And the background that I'm going to use to speak to you about is the results of the recent renewable procurement standard RPS procurements that were announced toward the end of the year; and the implementation of the least-cost/best fit methodology, which apparently resulted in some projects being selected that either did not have site control or did not have transmission. Which amazed me at the time that I read that because I thought that was the purpose of implementing the least-cost/best fit methodology.

And then the other important fact is the Energy Commission's voting out the net system power report, which indicates that we may be moving slightly backwards or at least kind of stagnant in terms of developing of new renewable resources.

And I think those procurements are symptomatic of a broader problem, in my view, about how procurement is being conducted in California today.

Now, following some of these procurements I have had an opportunity to discuss with some of my members who are very experienced developers of renewable projects throughout the country, and in particularly in California. All of them have generation in California.

They were limited in being able to tell me a little bit about these RFOs, because a lot of the RFOs that have been on the street have confidentiality provisions and so forth.

But one of the striking things that I discovered when I pried a bit was to find out that a number of very reputable companies, particularly renewable companies, were not bidding in the California RFOs, which surprised me. So, I've been working on trying to decipher exactly what the cause of that is. And asking them, you know, what are the barriers to development and why they're not bidding.

There are a number of barriers. And we are working on developing a systematic kind of litany of what these are. But I would like to focus in on two important barriers now.

The first is the lack of transparency in not only the planning process, but in the procurement process, itself. The lack of transparency in the planning process makes it difficult for people to prepare to bids, to get site control and so forth. Then the lack of transparency in the actual conduct of the procurement often makes it difficult.

When I ask companies how can they ascertain how the utilities get from point A, the release of an RFO, to point B, the announcement of who won, and does it make sense to them, they just don't have a good sense of that process.

And particularly the evaluation process. How they're being compared against other bidders in the process to identify what they could have done better to improve their project, or why they weren't selected in the first place.

There's really a curtain there that makes it difficult for IPP developers particularly to participate in this process in a knowing, informed way.

The other important problem that has popped up is the issue of high credit, high collateral in these RFOs. Most of the RFOs to date have been provided some collateral credit requirements that are kind of market collateral requirements which require developers to put up a tremendous amount of money up front. And that's something that we're going to try to work on and bring to the Commission's information about how to improve that.

But the overall conclusion that I've had is that it's costly to bid for any developers in California particularly. It's costly to prepare the response to the RFOs; it's costly to prepare sites to bid and so forth. And it appears that there are a number of very viable developers who are not bidding because the process is not known to them very well, and therefore they can't properly evaluate the probability of success.

And I just urge the state energy

agencies, the Energy Commission, the Public Utilities Commission particularly, to focus on this issue, improving transparency, so that more bidders can bid in these RFOs or are willing to bid and prepare. Because I think that is going to result in the lowest cost products to consumers and help lower rates while improve the efficiency of the overall system.

So, those are my comments.

CHAIRPERSON DESMOND: Thank you very much, Mr. Kelly. I believe there are some questions. Commissioner Grueneich.

COMMISSIONER GRUENEICH: Yes. You may not be aware, but at the Public Utilities Commission we have an ongoing proceeding that is addressing the issue that you've brought up, the transparency and I believe the confidentiality.

And I am the assigned Commissioner; and we have taken comments and briefing from parties. And I don't remember the exact schedule, but I believe that we are on course for releasing the proposed decision in May, with hopefully Commission adoption soon thereafter.

And I would expect that either IEP or some of your members have participated in our proceeding and presented the types of views that you have given us today.

And so what I wanted to let you know, and others know, that that is something that we are taking a look at. We're taking a full range of comments from the various parties and expect to have a decision out shortly.

MR. KELLY: That's great. IEP is a party to that proceeding, so I've taken the 40,000-foot-level perspective on this because of that ongoing proceeding.

CHAIRPERSON DESMOND: Mr. Kelly, a brief follow-up question. The Energy Commission published recently an analysis of contract failure for renewable projects and looked at it on a national basis.

From what you're hearing from your members and what was identified there, at least the report suggested similar failure rates across the country, and not just limited to California.

And I'm wondering if these issues are the same issues you see in other jurisdictions, or if you focused your comments here today on what you think are problems specific to California.

MR. KELLY: What I'm hearing from a

number of developers, both non-renewable developers and renewable developers is that California is unique in some of the conditions that they face. There are a number of companies that are actually developing projects outside of California, would be interested in California. And apparently are not bidding here for a series of reasons.

The credit and collateral one, for example, is one the word has come back to me is that it's just much higher hurdle for people, companies to cover here in California than anyplace else in the country.

CHAIRPERSON DESMOND: Is that only for the renewables, or is that true of any independent?

MR. KELLY: Yeah.

CHAIRPERSON DESMOND: Okay. Thank you. Commissioner Geesman.

COMMISSIONER GRUENEICH: I'm sorry, I had one follow-up. Do you know if IEP has put information on that issue in any of the ongoing CPUC proceedings?

MR. KELLY: I believe we have in the proceeding that's dealing with new development. I think we provided --

COMMISSIONER GRUENEICH: And that's the one --

MR. KELLY: -- a summary --

COMMISSIONER GRUENEICH: -- where we'll have our decision out in this summer then. So, that's an area where you've given us the information, given us more detail about the issue that you've raised, so that we'll have it before us in terms of a record.

MR. KELLY: I believe so. We've highlighted the issue, certainly, in the phase one proceeding that Sean was mentioning. We'll be happy to develop more detail if asked.

CHAIRPERSON DESMOND: Commissioner Geesman.

COMMISSIONER GEESMAN: I wanted to address the limited part of your comments that addressed planning assumptions and lack of transparency there.

And certainly as Commissioner Grueneich mentioned, the decision that the PUC will be making later this spring will hopefully address many of those concerns.

As I think you know, in our process last year, the Integrated Energy Policy Report, we were sued by the three investor-owned utilities to try to keep certain planning information confidential. It was the first time the Commission had been sued by the utilities since 1978.

The Sacramento County Superior Court found on behalf of the Commission's interest in disclosure on each and every count. And I think that you raise a good point. The degree to which some of this information is argued to be kept confidential really strains credulity.

Over the weekend I saw one of the utilities declining to respond to a newspaper reporter inquiring about hydro conditions because of concern that it would jeopardize competitive position.

And I think that until we're successful in getting at least the degree of information that we used to put out in the open 10 or 20 years ago, your industry is likely to face these problems.

MR. KELLY: And just to be clear in this, IEP's position is we're not particularly interested in the short-term net short of the utilities. These are the long-term views of where need is -- when it's going to occur and where.

So that particularly as we move to our localized resource-based approach, people need to see where those needs are going to arise so they can plan to prepare their projects.

CHAIRPERSON DESMOND: Mr. Kelly, as a follow-up on the subject of transparency, I sort of think of it in terms of three elements. There's a planning process that Commissioner Geesman just asked you about; there's the conduct of the bid evaluation, itself; and then there's the communication of the results, the disclosure of at what price and how much.

Can you prioritize what provides the greatest value in terms of allowing members to be more competitive in the next solicitation? Is it the planning? Is it the evaluation -- I know they're all important, but if you have to choose, I mean, how would you rank them?

MR. KELLY: My guess is probably some comfort with the evaluation process. The industries are fairly competitive. They pretty much know what it takes to put a project online. The importance of knowing, for example, the final bid winners is helpful in sending signals about the marketplace, and also helpful to know whether the evaluation process was occurred as you would anticipate.

If you bid six cents and all of a sudden you find out the winner was an 8-cent winner, for whatever reason, you might inquire why, how did that occur.

But I think fundamentally the big problem today is, first and foremost, is just that there's no understanding of how the utilities get from A to B when they evaluate these projects.

CHAIRPERSON DESMOND: Okay, thank you. Next speaker, Mr. Michael, is it Alcanter?

MR. ALCANTAR: Alcantar.

CHAIRPERSON DESMOND: Alcantar, with the Cogeneration Association of California.

(Pause.)

MR. ALCANTAR: Members of the Administration and Commissioners, I'm here seeking help. I've appeared before this Commission and the Public Utilities Commission for over 20 years, representing cogeneration interests and developers.

I am proud to say that I am one of those who's helped shepherd through years of regulation, facilities that Commissioner Peevey, when in another role, stridently supported and brought to the grid. And have been continuing to develop and supply resources to the state and enormous benefits to the state in terms of fuel efficiency, as well as delivery of reliable power beyond the skein of regulations imagination when they started. These are facilities that have performance factors well above 90 percent of online time.

I'm here because we are confused. As those who fall subject to your directions and those who are trying to interpret what policies exist in this state, I'm at a loss. And that's difficult when I'm trying to advise large clients, large power suppliers, large thermal suppliers, large fuel infrastructure suppliers in this state as to what they can do or should do in the future.

We don't have a policy as of yet. We've been promised for several years, and I think the latest promise is, don't worry, this summer we're going to have a decision for you that tells you what's going to happen for avoided cost pricing for cogeneration and for a long-term policy for cogeneration.

What's confusing to me and to all of us

is what I've tried to set forth in these few sheets. And I'm really not necessarily going to wander through each of them, but what I wanted to highlight here this is what, to us, the heart of the IEPR rulings were about, or process was about.

We want to require, we, the state, want to require the IOUs to maintain a policy that's been in existence for 30 years. We want you to buy this power from these kinds of suppliers. Just like this state has made a determination about what it wants to do with renewables and others, it looked in the past, 30 years ago. And it must look again today at what form of market we live under. Because it's no different. The mid '70s are no different than the mid 2000s here, where we are.

At that time there was a utility-dominated market in the '70s. The only suppliers that were entitled to get interconnection, entitled to get pricing from the utilities that was fair, more entitled even to get contracts for utility development projects.

And this state, unique, frankly, among the United States, embraced this policy wholeheartedly and recognized that that market, quote-unquote, that existed before the utility-dominated market did not work. We needed to do something else.

And so it set up these policies. We're going to have standard contracts. We're going to have avoided cost pricing that looks at incremental costs on the system so that ratepayers are kept indifferent, but utilities are buying from these types of facilities first.

We're going to require them to take the power that comes from these facilities so they're not shunted off to a we-don't-need-you-anymore, because we've purchased a Mountainview or we've developed another type of project that replaces the need for your project.

That isn't happening anymore. Utility views, and to some extent I must embarrassingly say the views of several staff members certainly at the CPUC, is market's market. You bid like everybody else.

And, of course, that's a very clever and flip answer, but it does not get to a public policy that works. We have an experience with that public policy. We didn't have cogeneration development before the implementation of PURPA and before this state embraced a series of policies to make it happen. And it's happening again.

This time I'm afraid by some neglect. Not from the CEC, because we were directed to come here. Commissioner Peevey, in a ruling issued in 2004, really directed all parties to say if you're concerned about where you belong in the so-called loading order, which facilities are going to be favored, which facilities need to be in the resource need plan for the utilities, come here and make that case. Here meaning the CEC.

And so we did. These were the results. We think there ought to be contracts; we think there ought to be an avoided cost; we think they have to have IOU procurement targets for these types of resources. We need to make sure that these units continue in their baseload functions as they have in the past.

In the implementation of all of these programs, and I'm going to skip through here a little bit because I really want to get to where the Commission came.

The CPUC, in a recent filing at the Federal Energy Regulatory Commission, we think sort of jump-started the decisionmaking process here. Made a filing, supported by staff, that indeed what the utilities were arguing about the future market, namely QFs bid in and good luck, cogenerators bid in and good luck. And if you can't meet the market needs we have, which is an entirely dispatchable, non-baseload facility resource, too bad.

That's not a solution we think; nor is it wise nor prudent public policy. And we implore this Commission to help us, this joint Commission, to help us understand what that policy is. Because right now I can assure you that the advice I give my clients is developing new cogeneration in this state is ill advised. It's not something that's supported. It's not something that gives you a secure policy or pricing or delivery protection. It is something that does not work or function.

Just a couple of statistics. I happened, in preparing for today's remarks, to go back and look at the available data, which is, as Mr. Kelly pointed out, pretty limited in today's world. But one thing that we found recently, and I think this was prompted, Dian, by your hearing, that the utilities have started again to provide information on their QF projects, as a whole, a report.

And we went back and found the last one that we could find, which was for PG&E 2000 and for Edison 2001. And compared them to the most recent filing, which was just in the very end of 2005.

What I found was troubling if the state's policy is to develop and grow cogeneration. In the Edison plan in the year 2000 there were about 170 cogeneration projects reported with contracts. In their 2005 filing there were 106. That's the wrong direction.

The recent Climate Action Plan report that has been so widely touted, and we think appropriately so. We're working hard to work on the implementation of that particular policy. Sends a signal to small CHPs and takes credit for the reduction in greenhouse gases associated with small CHP, very small.

And I submit that all of the CHP listed in the greenhouse gas report is dwarfed by a single one of our larger projects. And if one of those projects, one of the larger projects is lost, what isn't in that report is the negative that has to be figured in. You can't account for something once it's gone, and it's supplying the benefits of greenhouse gas benefits that are available from these resources.

What's enormously obvious about the benefits of a cogenerator is instead of creating two plants and the use of two fuels at two locations, it creates a single plant with single efficiencies. You have less emissions, by definition. And that's a credit that we need to take advantage of if that public policy is to go forward.

But I can't look at that report and equate it to a contract, equate it to a reserve of capacity for cogeneration resources, equate it to a price that our people can look at and make a defined or a determined assessment of to be able to go forward.

And as a result you're seeing a reversal of fortune of this industry. A policy that's been in place for 30 years eroding away by lack of focus or lack of attention, lack of, I think, decisionmaking.

We have, over the last two years, implored the CPUC to make these rulings and take actions. We have negotiated some contracts in a horribly unbalanced situation where there is no public policy and the only leverage, it's kind of like going to your mortgage banker and you complain about a particular provision in your mortgage loan. And the banker looks at you, blinks a couple times and says, "And your point?" And that's how the negotiations go with the utilities. They're no different than they were in 1975 when it didn't work.

So, I hate to be the ant at the picnic. I know there have been a lot of positive reports about many things that the state is doing in setting policies. But I think this is one that's woefully inadequately handled; not even mentioned in all of the slides that you see here today from the Commissions about what is going on with CHP and how are we taking care of this particular sector of the community.

Thank you for your time.

CHAIRPERSON DESMOND: Thank you very much. Anyone wish to respond? Mr. Gallagher.

MR. GALLAGHER: Well, the one point I'd like to make in response to Mr. Alcantar is that he's really mixing apples and oranges when he complains about the PUC's recent filing at FERC.

The issue there at FERC is that in the Energy Policy Act last year Congress decided, and the President signed the bill, that the mandatory QF purchase obligation under federal law would be eliminated if certain conditions were met. And those conditions include things like having a day-ahead market, which sellers like QFs can bid.

The question that FERC posed to parties is whether and when are these conditions going to be met in California. All our Commission's comments said was the conditions in the federal law will be met when the ISO implements its day-ahead market with the market redesign.

That does not prejudge any issue that's before our Commission. And it certainly does not prejudge whether our Commission should establish or maintain a must-buy obligation from cogeneration facilities and/or other QFs as a matter of state law.

That's a different question. It's one we haven't addressed. And it's one that our comments to FERC don't prejudge.

COMMISSIONER BROWN: If I could just say something.

CHAIRPERSON DESMOND: Commissioner Brown.

COMMISSIONER BROWN: There is -- Mr. Alcantar's statement may be a little ambiguous on one point, and that is whether or not there will be a decision by the Public Utilities Commission relative to QFs.

And, as I understand it, there will; it's scheduled. And a proposed decision is scheduled and being written now.

CHAIRPERSON DESMOND: Thank you. Commissioner Grueneich.

COMMISSIONER GRUENEICH: So, to clarify, if we separate out the issues that FERC is addressing and views on that, Mr. Alcantar, are the rest of the issues that you've brought up going to be the subject of the decision that Commissioner Brown just alluded to?

MR. ALCANTAR: I hope so. They are teed up. They are presented. They have been teed up for two other procurement decision proceedings, as well. And we have gone through several cycles to get there. We're hoping that that's the case.

COMMISSIONER GRUENEICH: Okay, so the items you raised today, as far as you know, then are going to be the subject of what we're going to be deciding, or what will be coming out as a proposed decision.

And, Mr. Gallagher, is that correct, from your understanding?

MR. GALLAGHER: I believe those issues are teed up, that decision, right, in the QF pricing decision.

COMMISSIONER GRUENEICH: Okay, thank you.

CHAIRPERSON DESMOND: Thank you. Commissioner Geesman.

COMMISSIONER GEESMAN: You know, I want to register pretty strong disagreement with the way you characterized the FERC issues. And I don't want to get in between your Commission and Mr. Alcantar. I'm not familiar with the issues in that proceeding.

But I think if you look back to the BRPU litigation initiated by Southern California Edison the FERC question here is a large, large, large part of the ballgame as it goes to encouraging this type of generation.

I'd raise the question what proportion of that 10.8 percent of renewable-generated electricity last year came from QF facilities. I've never heard the energy division as trusting of a market mechanism, let along an untested market mechanism as the MRTU day-ahead market.

And I think it's a bit beyond credulity to think that we simply provide a blank check for that type of mechanism yet to be developed and unwind the FERC must-buy requirement, which has been a cornerstone of state policy for almost 30 years. And we do that on a consent calendar with no debate, no discussion between Commissions, completely contrary to the Energy Action Plan-I or the Energy Action Plan-II? I don't think this passes the smell test.

MR. GALLAGHER: I guess I'd only -- I'm happy to respond, because I don't think there's anything to smell here.

(Laughter.)

COMMISSIONER GRUENEICH: We heard the ants at the picnic, so --

MR. GALLAGHER: The Commission's comments to FERC simply aren't anti-QF. They're not anti-cogeneration. The Congress has decided that as a matter of federal law the QF must-purchase obligation is going to go away at some time.

And that's a different question than the question that the Energy Commission adopted in the IEPR, where the IEPR recommended that the CPUC adopt a must-purchase obligation as a matter of state law.

Perhaps the Energy Commission adopted that recommendation in recognition of the fact that this issue was pending in the energy bill. I don't know.

But my only point is the Commission's comments were not intended to be read as anti-QF or anti-cogeneration. We recognize the value of cogeneration. We recognize the value of QFs. And we were simply commenting on a relatively narrow provision in the energy bill. That was our intent, anyway. And whether to adopt broader policies to promote or maintain cogeneration facilities is something that we're going to address on the record in a proceeding at the PUC.

CHAIRPERSON DESMOND: Thank you, Mr. Gallagher.

COMMISSIONER BOYD: Mr. Chairman.

CHAIRPERSON DESMOND: Commissioner Boyd.

COMMISSIONER BOYD: Perhaps you all

recall my earlier questions of our collective staffs about CHP and cogeneration just reflecting the concern I have. And I know the concern that this whole Commission has, but particularly, I think, Commissioners Geesman and I, who sat through 60 days of public hearings on all the energy issues, and are heavily responsible for what is in the IEPR that was relayed up there.

And there was a lot of consternation on this dais when we learned, as Commissioner Geesman indicated, that an issue had been taken up at the PUC and had even been moved to consent item, that sounded as though it was fairly significant.

I will admit I read all the background over the weekend and I decided on a legal -- I'm not a lawyer -- on a legal technicality perhaps the arguments you've been making are correct. And I'll leave it at that. And I will leave it to the PUC to address this issue.

But this is the second time in a major IEPR, 2003 first, 2005 again, where this body, the CEC rather, has been -- and it's reflected in the EAP -- have been very very supportive of the idea of CHP and cogeneration in general, as a very effective way to help work our way out of the morass we worked ourself into in this state with regard to electricity generation.

And I just want to strongly reiterate for your reading the IEPR and the quotes that are here, and I guess where you'll be hearing from this agency with regard to the need to move that along.

So, I'm not going to get into the legal argument. I tend to give you the benefit of the doubt on what you meant. And I tend to even read it that way as a non-lawyer. But I expressed earlier my disappointment that after sitting here for four years, and actually sitting as the Deputy Secretary dealing with energy for four previous years, we're having a hell of a time moving this subject matter along.

So, hopefully there's fire under the issue, and we can address the issue most thoroughly in what's before the PUC. But, just to let you know, it's beyond Commissioner Geesman and where he feels. It's shared strongly by the two of us, and was shared strongly by the entire Commission or it wouldn't have passed out a document, this Integrated Energy Policy Report, with some fairly strong language in it about what we should do in this arena.

And I hope my peers at the PUC take heart.

CHAIRPERSON DESMOND: Commissioner Brown.

COMMISSIONER BROWN: Yeah, is the Energy Commission a party to the process on the QF proceeding, do you know, Sean?

MR. GALLAGHER: I don't remember whether that's one where the Energy Commission Staff is joining us as collaborative staff, or whether that's one that the Energy Commission is a party to. I'd have to check.

COMMISSIONER BROWN: Okay.

CHAIRPERSON DESMOND: Mr. Saltmarsh.

MR. SALTMARSH: I'm going to probably go against better instincts, having the option to entirely stay out of this discussion, but stepping in anyway.

Commissioner Geesman, I would just offer, I say, not seeking any credit of the Electricity Oversight Board, that we declined to comment in the FERC proceeding on that issue. It wasn't teed up for a literal FERC decision now. They acknowledged that we don't have the market structure in place now. But the discussion is, is California in the process of implementing market structure that meets the Energy Policy Act requirements to make it go away.

I just wanted to offer the perspective that I think addressing this issue in state law is very much in the public interest, however each member believes it needs to be addressed. Because one of the reasons we declined to proffer prospective comments in that FERC proceeding was our perspective in dealing with FERC that their policy staff was highly inclined to find a way to lift that federal must-purchase obligation.

They're looking for the trigger; how soon they can do it. They would like to find that excuse. And so, if a clearly entrenched entitlement to have that power purchase is in the public interest, I think the state should address it soon because FERC wants to lift it.

COMMISSIONER GEESMAN: I would certainly agree with that. I think, though, as Commissioner Boyd was alluding, over the course of 60 days of public hearings we did develop a pretty strong empirical record and made conclusions in our report that we did not believe the conditions in federal law for competitive market in California were likely to be met in the foreseeable future.

So, it was with some surprise that we saw the consent calendar item after it was adopted.

MR. SALTMARSH: And I can't speak to that. I don't believe, if I read the filing at the time I don't have any clear recollection of it. But, just wanted to offer the perspective that when we discussed whether or not there was something to consider in making our own filing in that FERC docket, you know, we sort of thought we probably can't win that fight very long in favor of keeping the PURPA requirement in place.

So the way that the CEC appeared to be discussing, addressing it in state policy is probably the better thing to hang our intentions on.

CHAIRPERSON DESMOND: Mr. Saltmarsh, not to continue to beat a dead horse, but this is an important subject. Mr. Gallagher made references to state policies that may be taken in order to continue to provide support for that. I note you, yourself, have been involved in federal preemption discussions with FERC as it relates to contract issues and cost recovery.

Wouldn't the same concern also rise here, that if California took steps to take, in support of CHP, that we would still face potential challenges under federal preemption, though?

MR. SALTMARSH: I don't believe so. There's no affirmative federal law prohibitions in the State of California as a buyer or, in this sense, as the regulator of a buyer, can pretty much make whatever rational choices it wants for what kind of power it's going to buy, and not run afoul with federal law. As long as it's not constitutional discrimination such as saying we're going to buy exactly the same kind of power, but we'll only buy it from three miles this side of the border, not the Arizona side, or that type of thing.

But as long as there's a rational basis to prefer renewable or cogeneration or something else, I think we're fine.

CHAIRPERSON DESMOND: Okay. I just want to make sure we clarified that. Thank you.

We have two other speakers here, at least identified, both on the same subject. First, Kelly Lucas with Mid-Set Cogeneration.

Followed by Audrie Krause.

And all I'd ask is if you're adding any different points, or simply support the previous speaker, please let us know.

MR. LUCAS: I'll be adding to the previous speaker, Mr. Alcantar. I'm not sure if I'm invited to the picnic or whether I'm an ant that's invading it, so.

I have some prepared remarks. Good afternoon and thank you for the opportunity to comment. My name is Kelly Lucas and I'm here representing four cogeneration companies, of which I'm the Executive Director. Currently about 160 megawatts of power. I'm also associated with two other facilities of 600 megawatts cogeneration power.

For the past 15 years these central California cogeneration companies have been selling steam to oil producers to help lift California's heavy oil to the surface, and selling power to PG&E for use by its customers.

Three of the PPAs are set to expire in less than one year. One has expired, and we're operating under a temporary SO1. To a point that was made earlier by Commissioner Rosenfeld, wish he was here, one of these facilities has a thermal energy storage system, and that is we make ice at night and we augment our power production during the day, which is we had the discussion about the critical price of peak pricing. And that's exactly what this power is intended to serve.

These companies have made substantial investments in California as a result of sound and stable regulatory policy that this state has promoted. Charles Warren, a former chair of the California Assembly Utilities and Commerce Committee, who went on to serve as a Cabinet Chairman to the Council on Environmental Quality, made the following comments on cogeneration in late 1980s which still hold true today:

Cogeneration fits the state's power supply objectives by being both an efficient and environmentally benign preferable technology. Cogeneration meets such a wonderful niche, both economically and environmentally its future should be secured and protected by any means necessary."

So today I hope you can appreciate why I'm troubled by the PUC's decision to support proposals that could effectively eliminate much of the state's existing cogeneration, especially since California has been a pacesetter in meeting its energy demands through conservation, wind, solar, geothermal and cogeneration.

In the last 20 years the cogeneration facilities I'm associated with have helped deliver to California refineries an incremental 189 barrels of oil to help fuel California's economy. How did this happen? It happened through the process of cogeneration.

By combining the processes of producing electricity and steam through cogeneration, less natural gas is burned to sequentially produce electricity and steam, which allows more oil to be delivered into California market; more natural gas to be available to residential and industrial users; and fewer emissions produced.

Cogenerators made significant capital investments which came about because this state's policies were clear signals to cogenerators and industry that the long-term power purchase agreements offered by the utilities could be relied upon. The PPA's price stability produced the necessary credit capability that allowed for long-term arrangements with fuel and equipment suppliers to help cogenerators achieve availability on times well into the 90th percentile.

The cogeneration industry depends on consistent and stable public policy relative to power pricing. Equipment and fuel suppliers and banks extending credit to cogenerators need to see continuing regulatory support and stability.

I urge the PUC to promote and approve the type of contract certainty that helped cogenerators deliver these results to California's economy over the last 20 years by requiring utilities to offer power purchase agreements that contain sustainable power pricing and term lengths.

Thank you very much.

CHAIRPERSON DESMOND: Thank you very much. Our last speaker, Audrie Krause, Communications Director with CogenWorks.

MS. KRAUSE: Thank you and good afternoon. I will be very brief since I realize I'm the las speaker. And my comments do follow on Mr. Alcantar's and Mr. Lucas'.

I'm here representing CogenWorks, which is a coalition of about 60 different members representing cogenerators in California. And, as some of you know, I'm also the former Director of TURN.

We are appreciative of the Energy Commission's efforts with both the Energy Action Plan-II and the 2005 Integrated Energy Policy Report in recognizing the benefits of cogeneration. And rather than reiterate them, since they've already been discussed, I'm just going to thank the Energy Commission and address the rest of my comments to the members of the Public Utilities Commission who are here.

Right now you are engaged, as has been noted, in some lengthy proceedings that could implement policies that would promote cogeneration in California. And your decisions are due this summer.

But at the same time that you're contemplating those decisions, you're lobbying both in Washington, as has previously been discussed, and in Sacramento for proposals that could effectively eliminate the business environment that's necessary for continued operation of our existing cogeneration and investment in new facilities.

These actions appear to be being made

without regard for the comprehensive factual and legal record that the staff is compiling, which is supposed to inform the policy decision. We don't know why you're ignoring the Energy Commission's recommendations and lobbying for policies that are at odds with those recommendations. But we do know that cogeneration is efficient, reliable, cost effective and environmentally sound.

So I'd like to ask those of you who are here from the Public Utilities Commission to publicly pledge to implement the Energy Commission's recommendations. And if you're not willing to make that pledge, I'd ask that you explain why.

Thank you for your time, and I'd be happy to answer questions.

CHAIRPERSON DESMOND: Thank you very much. Commissioner Brown.

COMMISSIONER BROWN: I don't think that that is an appropriate comment and I'll tell you why. Because there is a ongoing proceeding at the PUC, okay. For us to make a comment at this time to commit ourselves to any particular decision would disqualify us. We are supposed to approach that decision with an open mind and not in a committed statement -- with a committed statement.

PRESIDENT PEEVEY: The only thing I would add to the last three speakers is that, you know, after I get over my disgust with your comments to some degree, is the following:

That Commissioner Brown and myself and former Commissioner Kennedy kept many projects open and alive over the last few years in the face of unremitting opposition by our two colleagues, frankly, thank God, moved on.

That's the past. And I personally am a strong supporter of combined heat and power, cogen, whatever you want to call it. And the utilities, you know, it's fair to say, have been harsh in many cases. We've kept these projects alive.

But we're not going to, at the Public Utilities Commission, give a blank check. We have a responsibility to ratepayers. For someone to get up here who used to run TURN and pleaded constantly, constantly for the ratepayers in terms of short-term advantage, even at the risk of long-term cost, I find it particularly, you know, somewhat unsavory, so, to now come and make this special plea on behalf of a select group.

We will treat these people fairly. We have; that has been our pattern; and we'll continue doing it. Fairly does not mean you get everything you ask for under all circumstances. It's that simple, you know. Sorry.

MS. KRAUSE: If I could just respond to that, Commissioner Peevey. My understanding is that ratepayers are not affected one way or the other under the avoided cost methodology.

COMMISSIONER BROWN: Why don't we just wait until this comes out.

PRESIDENT PEEVEY: As Commissioner Brown said, I mean we have a quasi-judicial role here. We're trying to approach this thoughtfully and considerately, weighing all the factors. And I think that at the end of the day most reasonable people will conclude that what we come up with, I'm willing to venture, is a fair decision.

That doesn't mean it'll satisfy all under all circumstances. But we will do our best. And that's what we're sworn to do, and we try to do, with full consciousness of the interests of ratepayers in that process.

COMMISSIONER BROWN: And I must say, Ms. Krause, I have no view on this. I'm waiting for the decision. I will listen to the comments, read the comments and listen if we have oral arguments, with an open mind. That's all I can promise you.

MS. KRAUSE: Thank you.

CHAIRPERSON DESMOND: Okay, thank you. Unless there's any other public -- members of the public who wish to address this group, I'll simply leave it now to any closing comments or thoughts the folks here would still like to make.

No to my right. No to my left. Well, I want to thank everyone for coming here today. We shot for 1:15; we started 15 minutes behind. Not too bad.

So, thank you very much, it was a very helpful discussion.

(Whereupon, at 1:30 p.m., the Joint Public Meeting was adjourned.)

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CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission/California Public Utilities Commission Joint Public Meeting; 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 meeting, nor in any way interested in outcome of said meeting.

IN WITNESS WHEREOF, I have hereunto set my hand this 3rd day of May, 2006.