COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	)	
	)	
Preparation of the 2008 Integrated (2008 IEPR)	)	Docket No. 08-IEP-1
	)	
Energy Efficiency and Demand Forecasting	)	

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

TUESDAY, MARCH 11, 2008

1:07 P.M.

ORIGINAL

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

COMMISSIONERS PRESENT

Jeffrey D. Byron, Presiding Member

Jackalyne Pfannenstiel, Associate Member

ADVISORS PRESENT

Gabriel Taylor

Laurie tenHope

Tim Tutt

STAFF PRESENT

Michael Jaske

Lynn Marshall

Tom Gorin

ALSO PRESENT

Simon Baker
California Public Utilities Commission

Lara Ettenson
Natural Resources Defense Council

Herb Emmrich
Southern California Gas Company

Greg Katsapis
San Diego Gas and Electric Company

Richard Aslin
Pacific Gas and Electric Company

John Gillies
Southern California Edison Company

Robert E. Burt
Bobburt
Insulation Contractors Association

ALSO PRESENT

Jane Turnbull
League of Women Voters

Ken Glick, Senior Attorney
NorthernStar Natural Gas

Michael Rufo
ITRON

Jacqueline Jones
Southern California Edison Company

Pete Skala
California Public Utilities Commission

I N D E X

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P R O C E E D I N G S

1:07 p.m.

PRESIDING MEMBER BYRON: Good afternoon, everyone, and welcome to our workshop here. And I want to properly read the title of the workshop. 2008 Integrated Energy Policy Report Committee workshop on energy efficiency and demand forecasting.

I am the Presiding Member of the 2008/2009 IEPR Committee. To my right is my Associate Member, the former Presiding Member of the IEPR, Jackalyne Pfannenstiel. And her Advisor, Tim Tutt. My Advisors are also joining me here at the dais, Laurie tenHope and Gabriel Taylor.

If I could, I was just going to say a couple of things first to give some context of what we're doing; and then, of course, ask if you have any comments.

We're a little bit out of order with this workshop in that we haven't really held a scoping workshop yet for the next IEPR, which is typically the process, as I understand it.

But in the 2007 Integrated Energy Policy Report there were several parties that requested

that the Energy Commission provide additional information on the ways in which energy efficiency is accounted for in our forecasting models.

So, in addition to the staff discussing those methods and assumptions that they use to prepare consumption and demand forecast, we're also interested in hearing how the parties today use these forecasts and a number of other questions that are listed in the notice for today's workshop, which I'm not going to repeat.

We're going to be conducting a scoping workshop in the next month or so, but there's a lot of material to cover this afternoon in a somewhat foreshortened time period. And we apologize for that, there were some obligations that the Chairman and I got pulled into today. But I think we can get it all done, according to the schedule we've got.

I'd like to thank you for being here, for accommodating our change.

Madam Chairman, did you have any comments that you wanted to add?

ASSOCIATE MEMBER PFANNENSTIEL: Thank you, Commissioner Byron. Let me just comment that this really is a new day, if you will, a new IEPR

cycle. And there's a lot that we will be considering through our scoping workshop that we want to raise this year.

But this issue of today really is a left-over one from the 07 IEPR. But we really can't get going on the 08 until Commissioner Byron and I are clear on what this means. What the demand forecast really is that is going to be acceptable to all of the various parties in the state that use it.

Clearly, by the end of the year last year we hadn't reached agreement. There was remaining uncertainty and controversy over what was in and what wasn't in this forecast.

So we agreed that we'd just put it on the table first thing; get it, we hope, understood by all parties. And so people don't all have to agree, but they do all have to understand it. So I think that's my goal for today.

PRESIDING MEMBER BYRON: Thank you very much. The format will be such that we're going to do a little overview of the workshop and the issues. And then we'd like to hear right away from the parties on their responses to the questions that we've got, correct? All right,

you'll correct me if I'm wrong.

And staff, the staff is going to do some presentations on the demand forecast methods. I see that we will hear from the utilities and then there's a presentation on quantifying energy efficiency, followed by public comment, is that correct?

That looks all right, then. Can we get started with -- did you want to say anything before we get started?

In that case I'd like to take just a moment before we do our opening presentation here. I see that Dr. Jaske is going to give us the overview and objective. And I suspect a lot of you know this gentleman.

If you wouldn't mind, do me a favor, raise your hand if you know who Dr. Jaske is. All right. Well, you know, this guy keeps showing up all the time. And I decided to do a little investigating on his credentials.

(Laughter.)

PRESIDING MEMBER BYRON: And, Mike, I'm going to take a minute and I'm going to read a few things here so that everybody understands at least why you're presenting today, if not all the time.

Most of you may not know that Mike, Dr. Jaske, currently provides support to the Executive Director of this Commission as a member of the Strategic Issues Integration Group.

For 20 years he was the chief demand forecaster giving technical direction for the Commission Staff's independent demand forecast. Dr. Jaske has played an active role in the development and advocacy of the Energy Commission's positions on retail market structure. His recent focus has been on developing dynamic pricing tariffs and integrating them into our plan process.

He's been involved in numerous collaborative efforts between the Energy Commission and the PUC. Notably, one, to create demand response capabilities; two, integrate planning and procurement activities of the two agencies; and three, the PUC's resource adequacy proceedings.

A recent emphasis has been on evaluation of the greenhouse gas emission reduction potential of energy efficiency; supply side renewables; and rooftop solar photovoltaics.

He's an important participant in the

Western Energy Coordinating Council loads and resources subcommittee, developing resource adequacy methodology for WECC. Dr. Jaske also provides support to the Energy Commission's PIER-supported research and market design and performance.

He's testified countless times before the Energy Commission, the PUC and the California Legislature. Dr. Jaske is a member of the IEEE Power Engineering Society and he serves on the Energy Policy Committee of IEEE USA to educate national policymakers on electricity issues.

And, Mike, I was pleased to see this, a bachelor of science in chemical engineering from Oregon State, a masters and PhD in system science from Michigan State.

So, I hope I have not embarrassed you too much. But I think it's important everybody know that we're fortunate to have you at the Commission.

DR. JASKE: For the record, my name's Mike Jaske.

(Laughter.)

DR. JASKE: And what I'm hoping to do today is to provide sort of an overview of why

we're here and talk about some objectives.

I think there are two broad questions that bring us here today. The first is clearly the kind of thing that the Chairman spoke of just a moment ago. And as she said, this question arose at the tail-end of the IEPR process, the 2007 IEPR process. And there really wasn't sufficient time to --

PRESIDING MEMBER BYRON: Mike, can you move forward a little bit so everybody can hear you better.

DR. JASKE: -- to dive into it in detail. But, also, in the comments made on the draft IEPR and the Committee final IEPR was a parallel question. And that is given the Energy Commission load forecast were the incremental energy efficiency impacts taken from the energy efficiency potential study really ones which could be achieved. Or if they could be achieved, could they be achieved at the costs that were identified in that project.

And these are two highly related questions, both of which I think are important to different audiences for Energy Commission analyses. And are sort of variations on the same

subject.

So, if we're going to try to deal with those two broad questions, how would we go about that? Well, clearly we need to know what's in the staff demand forecast, and we'll hear, in considerable detail, from Lynn Marshall and Tom Gorin about that. And there are materials that were included as part of the revised staff documentation back in November. And then additional ones submitted into the docket more recently.

But there are also innumerable things having to do with program design details, either of the 06 through 08 program groupings, or the perspective 09 through 2011 efficiency programs that we haven't heard about, and that are really essential to understanding the degree to which their impacts might or might not already be in the Energy Commission load forecast.

So one of the important things that I think is before us is this question of if we then understand those programs sufficiently well, and I don't think we know yet what really takes to satisfy sufficiently well, how would we then compare what is in the sort of gross evaluation of

those programs versus what's in the forecast to determine something that might be thought of as a net impact or an additional incremental impact.

And then finally, given that this issue surfaced to some degree in the 05 IEPR, was tackled with some limited forward progress in 07, what do we really need in terms of our processes, both here at the Energy Commission, at the PUC, and perhaps even other forums like the ARB greenhouse gas implementation effort, to come to grips with resolving it, or if not resolving it, at least narrowing the uncertainties.

So I'm going to quickly deal with each of those broad questions here in a few slides. Just to sort of key up what we need to be talking about.

So, how is energy efficiency incorporated in the staff's forecast. Clearly we'll hear a lot about that today. We need to understand how programs of various sorts, standards, various codes and then utility programs are included in inputs to the models. Models, plural. There are several different models; each have their own characteristics and their own strengths and weaknesses.

What programs aren't quantified in the models directly but are quantified separately in some manner. And then have effects that are subtracted off, call it the raw result, to get a final forecast.

Additionally, what non-programmatic effects, either through price response or market effects or just other trends going on out there in the consuming world, are in the models or not in the models. And how can we deal with that or those.

If we're going to better understand proposed energy efficiency programs, or the potential studies like the ITRON study released in 06, then what do we need to know about them in order to be able to compare them to load forecasts.

Well, first of all, you need to have quite a bit of information about the nature of the program. It doesn't really do any good to say, you know, here's a hypothetical body of energy efficiency and it's x-thousands of gigawatt hours. There's nothing one can do to compare that to what's in the forecast.

You have to get down to programs; you

have to get down to some level of detail about the design of those programs; what customers they're targeting; what kind of measures they're proposing to incent or otherwise cause customers to adopt.

Programs that are highly specified or ones that are more readily compared to what's in the forecast; ones that are very flexible that allow lots of freedom on the part of the end-user to respond to information or packages presented by the utility will be very much more difficult to quantify.

And then similarly but not exactly the same, for potential studies there's lots of measure detail in the potential study. It's essence is to build up from the measure level. So that allows sort of automatically a comparison to the end uses of the load forecast. But how do we understand how to get high penetrations of those measures. How do we understand the high end measure cost -- the cost of the program to achieve high measure penetrations.

As I understand it, the main focus of the potential studies really has been more in sort of near-term side of the supply curve, if you want to think of it that way, as opposed to the top end

of the supply curve.

And additionally, are those studies, themselves, limited by their focus in the PUC forum for IOUs and the IOU program delivery mechanism. Are there other means by which these measures can be delivered to consumers that are more appropriate. Do they cost different amounts to achieve that. And in the IEPR, itself, this issue was recognized and sort of summarized in terms of the question of whether there ought to be new means by which efficiency can be delivered to end-use customers.

So if we have a better understanding of programs or potential studies, how are we going to try to reconcile those with load forecasts. Something like this sequence seems appropriate. You have to identify some protocols that's going to cause this to happen. You're going to have to basically understand program designs at some level of detail.

We're going to have to line up the measures either in programs or from the potential studies with the end uses in the forecast. And sort of be able to compare them. These kind of quantitative comparisons have to sort of deal with

the interactions among the programs.

The higher the level the penetration of the measures, the more programs might be overlapping with one another relative to near-term programs where there is some differentiation that's possible.

And finally, of course, there is this underlying issue of if there is a large percentage of programs or potential that's already embodied in the load forecast, what does that mean about decisions to go forward with those programs. Are they not cost effective because their impacts are already included in the forecast. Or is there some back-and-forth between the forecast and programs that's necessary and appropriate that needs to be taken into account in making cost effectiveness decisions.

Another challenge we have that I won't pretend to say I understand how to resolve is how do we deal with the alternative objectives that various seemingly similar, but perhaps not exactly the same, objectives have.

So in our IEPR forecast generally we think of the objective as having an accurate portrayal of load that's going to happen.

Those forecasts are frequently used in several different settings depending upon the time horizon. There's the near-term forecast which has become embodied in the resource adequacy process. There's the sort of intermediate term that the 2006 LTPP proceeding decision just adopted, which is the procurement application. And the desire to use those as the basis for giving procurement authority to the IOUs.

And there's perhaps longer term applications in transmission studies that go all the way out to ten years. And then there's perhaps even further out efforts like the AB-32 implementation process that's looking at 2020 right now. But according to the Governor's executive order, we need to be considering the next decade or decades beyond that.

So perhaps the forecast will become very uncertain that far out, and there's a different kind of bounding of what loads might be that's appropriate the further and further you go out. But, generally, accuracy is some predominant objective.

When we're doing potential studies perhaps there's a whole different notion of what

is the objective. We're trying to understand the entire body of energy efficiency. So we have segments of the potential that have served different purposes.

We have the technical potential; supposed to be the roster of everything we can now identify including even emerging technologies that aren't yet operational, but we speculate might become available in 2012 or 2015 at some cost.

We have subsets of that which we label as economic. They're economic relative to something. We use a cost effectiveness test to identify the resources that are going to be displaced by those efficiency studies.

We have even lesser amounts that are sort of seeming to take into account the alternative contributions of market penetrations versus the things that utility programs can actually deliver. At least utility programs as we've known them.

And there was controversy in the 2007 IEPR process about achievable versus full economic potential. Those are ways in which the potential studies, themselves, are already segmenting, you know, the full body of measures and trying to

provide some kind of bounds around portions of it.

There's the kind of application that the scenario analysis did that wants to say, okay, we have a seemingly difficult GHG goal to achieve. What's the most energy efficiency we can imagine. So it's a more what-if all of that was to happen, what would the impact of that be, what is a rough idea of costs. So it's not intended to be as precise as a forecast. It's being used to guide policy.

But close on the heels of that is the actual GHG compliance process and options that individual load-serving entities perhaps are going to be asked to take on as mandated requirements or strongly encouraged goals, because if they don't, you know, some other element of the overall program will cause them to have to acquire tradeable credits or some other monetary inducement to go as far as they can, or as far as their individual goal has been developed.

All of these are sort of variations on the same thing. They relate to one another, but they're not the same as one another.

So, part of our objective here at our workshop is needing to sort some of this out and

identify, if we're going to be making progress over some period of time following today's workshop, what are we trying to achieve.

Which then leads to this slide. I think we're going to get a better idea of what the nature of these questions and the approaches to dealing with them today, but we're only at the very beginning of a multi-month process. We're not going to solve this question today. We're not going to solve this question next week or next month.

We can maybe make progress in three months or six months, but progress might be measured by only diminishing the level of uncertainty that we have about this overlap between what's incremental to the forecast and what's in the forecast.

We need to go through some series of specifics like this, which I won't dwell on because we can talk about that more at the end of the day. And what do we need to do, if anything, to adopt, as an interim adjustment to either the forecast or to the programs.

The PUC chose in its 2006 LTPP proceeding to say that 80 percent of the

incremental program effects were already in the forecast. And only 20 percent would be of incremental savings relative to that forecast. That may be sufficient to allow the forecast to be used for the procurement purposes that that proceeding is focused on.

Is that also an acceptable approach if the forecast is used as a foundation for transmission studies or other applications of the forecast that need to be implemented while we're working on, if not solving, resolving these questions.

Part of the issues associated with developing that game plan are the schedule. Here are a number of things. Again I won't dwell on each of them. But they're all elements of when new information becomes available, or when new results might be needed. Those need to be taken into account in developing our game plan.

So, today in this initial workshop in this process, it's important, as the notice set forth, that we understand who the clients are and what their applications for the load forecast are.

We'll get a much better idea at the end of this workshop through Tom and Lynn's

presentation about what energy efficiency is already included in there; what is not; how it's quantified.

And we'll have some idea from the utilities and perhaps others who are interested in doing these things, themselves, how they treat some of these same issues.

I took a quick glance at the presentation from SoCalGas and San Diego Gas and Electric, and they lay out an architecture of an end-use model that's in many ways similar to what staff uses. And they may have some insights about how what they do does or doesn't match up to what staff does.

So, that's my opening presentation. Are there any questions from the dais?

PRESIDING MEMBER BYRON: Quick question, Mike. Back to the next steps for the process where you talk about adopting interim approaches, I'd like to just get a better understanding from your perspective as to what you think is going on there.

I mean, the holy grail, I take it, is the ultimate forecasting model, the theory of everything tied up in our forecasting model. Can

you elaborate on interim approaches?

DR. JASKE: I think we need to be really clear that there's certain things that are appropriate to include in the demand forecast, itself.

There are other, and certain things meaning degrees of energy efficiency, elements of the CSI objective to have rooftop PV, which is not something we're talking about explicitly today, but which is highly related.

We tend to include in the forecast things that are considered committed. We don't put in the forecast things that we desire but which we consider uncommitted, even if they're a goal. We keep separate these things that are in the forecast which we use. And we do that partly because we're trying to do more than one thing simultaneously.

We're trying to have a forecast which is the basis for planning and for commitments like procurement, but we're also wanting to keep track of other elements of our preferred resources, other established goals.

And so we need to sort of carry along that concept all the time. There's a certain

amount of things that are appropriately in the forecast; and then there's another body of energy efficiency, of rooftop PV, other end use things, other elements of distributed generation that we might like to have, but which we don't think are ready to include in the forecast.

We aren't certain enough that they're going to happen that we're wanting to diminish our procurement activities in other, you know, utility RFO processes until we're more certain that these things we desire are going to happen.

And so there's a constant tension between what's appropriately in the forecast, what's carried along in parallel to the forecast, and how much effort do we put into quantifying those parallel quantification efforts.

We actually haven't done much until the scenario study to look at the high level of energy efficiency that's in the ITRON potential study. We've tended to pay attention to what the utilities have in their procurement plans as the next increment of energy efficiency programs that are not considered committed, but which everyone is sort of willing to carry along on the books as a way to fill that resource need.

But we've largely, from the Energy Commission's Staff perspective been content to record what the utilities have included in their procurement plans and not to independently quantify those increments of energy efficiency or PV or distributed generation.

PRESIDING MEMBER BYRON: Thank you, Mike. I have noted that we have another presentation when we get through here, correct? No?

MS. MARSHALL: We're going to parties --

DR. JASKE: Yes, we're going to parties, but --

PRESIDING MEMBER BYRON: All right, good.

DR. JASKE: -- but I think it would be appropriate that we start with the PUC Staff --

PRESIDING MEMBER BYRON: Good,

DR. JASKE: -- because PUC has made an important statement about how it is it wants to deal with this question of energy efficiency relative to the forecast.

PRESIDING MEMBER BYRON: Good.

DR. JASKE: We need to hear from them first.

PRESIDING MEMBER BYRON: All right, thank you. And, Dr. Jaske and Lynn Marshall, Tom Gorin, I'd ask you to also feel free to ask any clarifying questions from the presentations we're about to hear, okay?

DR. JASKE: So, if I could have --

PRESIDING MEMBER BYRON: Who's up first?

DR. JASKE: I think Simon Baker of the PUC is going to make their presentation.

MR. BAKER: Good afternoon, everyone. I'm Simon Baker; I'm with the long-term procurement staff of energy division at the CPUC. And I'm currently the lead analyst on the 2008 LTPP proceeding which kicked off just recently, February 15th of this year.

And at the start I have to apologize for getting the date wrong here; I think I got over-zealous on spring-forward daylight savings. Today is March 11th.

So, I'd just like to make an initial comment on CPUC's long-standing position on the load forecast. Just to bring up some history, back in 2005 in an Assigned Commissioner Ruling from President Peevey, the so-called IEPR ruling, basically said that the CEC's IEPR forecast is the

state's official forecast. And that the LTPP proceeding shall be based on that forecast.

And that our Commission does not intend to re-examine the load forecast issues in the LTPP proceeding except for very narrow exceptions. And those had to do with materially new information or materially changed circumstances. And the burden of proof would really be on the parties to substantiate that in our proceeding.

PRESIDING MEMBER BYRON: Simon, forgive me for interrupting, but I've never had opportunity to comment on this in my tenure, but I think this is a -- I'll commend President Peevey again for this. I just think it's fantastic that the PUC does recognize the IEPR's forecast. It sets the bar and gives us an opportunity in a public forum to try and get it right.

So, we thank you very much for that. And also thank you for being here today.

MR. BAKER: Well, thank you for your support.

In December of last year we issued the long-awaited decision on the 2006 LTPP proceeding. And in that decision the Commission reaffirmed its long-standing position, and also identified that

quantification of energy efficiency in the load forecast was a high priority.

In the recent 2008 LTPP order instituting rulemaking the load forecast EE issue was placed in scope. And the CEC's IEPR update process was identified as the proper place for that to be resolved.

So, our Commission's expectations of the IEPR update process is that the IOUs and the parties will fully commit themselves to resolving all the issues related to load forecast in the IEPR process. And that the LTPP will not be an alternative forum for relitigating these issues.

And our organization commits to bringing its expertise, consultants working on the efficiency potential studies. We have our energy efficiency staff here with us today. And we commit to participating in this process to satisfactorily address the issues for the short term, so that we get a forecast for the next LTPP cycle that everybody feels better about, and also for the long term.

So, where does this process fit into the LTPP proceeding? Well, the LTPP proceeding is the CPUC's ten-year forecast that assesses loads and

resources, and authorizes new conventional generation to be procured.

And that ten-year planning horizon is longer than the timeframe for other resource proceedings. For example, energy efficiency operates three to four years out. The new energy efficiency program portfolios for the years 2009 to 2011 will be coming out this year. But, for example, the next LTPP cycle will be looking out to the year 2020. So there's an incongruence there that needs to be resolved.

The need determination and the authorization for new procurement that takes place in the LTPP proceeding is essentially just a loads and resource balancing exercise according to the loading order policy.

It starts with a load forecast and then preferred resource forecasts are then injected into the analysis, resulting in a calculation of a residual net short or a long position. And then new fossil procurement is authorized to fill that net short position with adequate lead time. And we're looking at anywhere from a five- to eight-year forward timeframe for authorizing that new generation so that projects can get built in a

timely fashion.

The forecast EE, and in this case it's the energy efficiency goals of our Commission, appears in two places. On the load side, so-called committed energy efficiency, is embedded in the forecast. And on the resource side, uncommitted energy efficiency is treated as an incremental resource that reduces that net short position.

ASSOCIATE MEMBER PFANNENSTIEL: Simon, would you make sure that we all understand what you mean here by committed and uncommitted?

MR. BAKER: There's a discrepancy in the two Commissions' definition of the committed EE and uncommitted EE categories.

The CPUC's definition for committed EE is energy efficiency that results from utility actions in the current energy efficiency portfolio. So, for example, in the 2006 LTPP proceeding, the committee EE was basically utility actions as a result of 2006 to 2008 energy efficiency programs. And anything that preceded that.

Uncommitted EE would be anything beyond 2008, whether utility actions or naturally

occurring or market effects or price impacts, or what-have-you. All of that would be considered uncommitted.

That clarifies CPUC's definition of committed and uncommitted. And I think that as the workshop continues on we'll be hearing more about what the CEC's definition of committed and uncommitted is. I think that's part of the work that we have to do, is to understand that.

So, this presents an overlap factor in the LTPP proceeding where some of our Commission's energy efficiency goals are overlapped with the load forecast.

And in the December decision our Commission assumed that there was an 80 percent overlap factor; 80 percent of the energy efficiency goals were captured already in the forecast and 20 percent was an increment as a resource. And that was for PG&E and Edison.

But our Commission found that these issues needed to be better understood and a robust methodology is needed.

So in the energy efficiency proceeding our Commission approves energy efficiency goals based on EE potential studies. And we have a

long-standing and highly developed evaluation measurement and verification infrastructure to quantify and attribute savings based on utility actions.

In a 2007 decision we adopted incentives for IOUs to promote energy efficiency; and those are based on cumulative energy savings goals. And finally, the focus in the energy efficiency proceeding is on energy savings. The goals, themselves are set in terms of megawatt hours. And capacity savings are derived based on an assumed load factor.

In the GHG proceeding, which is the joint CPUC/CEC recommendations that will be going to ARB, on AB-32 regulatory structure, there's a modeling project underway to evaluate the cost of CO2 reductions in the electricity sector. And efficiency is the first loading order resource to meet forecasted load.

While the modeling used is a CEC load forecast as its basis, but quantification of efficiency resource potential and cost is a critical assumption because of the prominence of energy efficiency in the loading order.

And just as a side note, I understand

that current the modeling assumption for the business-as-usual reference case is that 100 percent of the energy efficiency goals are embedded in the load forecast.

So, from our agency's perspective one potential timeline for deliverables would look like this. The basic inputs from CPUC feeding into the IEPR update process would be the potential studies, themselves. Which our consultant, ITRON, is currently conducting and is targeted for approximately a March delivery date.

Then you have the IOUs producing 2009 to 2010 program portfolios and submitting those to our Commission on May 15th. And concurrent with that you have a statewide energy efficiency strategic plan which would be looking beyond that 09 to 11 time period, and looking at further strategic developments in energy efficiency, getting at some of the out-years and some of the emerging technologies that Mr. Jaske was referring to earlier.

The analysis, as we've said, would take place here at CEC, but with significant CPUC assistance. And we commit ourselves to this process and to assisting in the analysis, itself.

And in terms of results we would be looking for, at best, if, in July, there are any preliminary results coming out of this process, the GHG modeling phase two could potentially readjust some of its assumptions to reflect those preliminary results.

But certainly by April 2009 when we anticipate a scoping memo for the 2010 LTPP plan cycle, we would be looking for results by then.

So, in terms of how we plan to submit comments in the IEPR process, we'd like to express our intention to collaborate on this process. And we have exchanged informally some questions and comments with the demand analysis office's staff. And we plan to submit some version of those comments as input.

And that does it for me. Any questions? Thanks, again.

PRESIDING MEMBER BYRON: Thank you. Any questions? Tim, I'm sorry.

MR. TUTT: Good afternoon, Mr. Baker. Can you provide -- give an idea of why the GHG analysis uses a different amount of EE embedded in the load forecast than the long-term procurement proceeding? I understood you to say 80 percent to

the utilities in the LTPP and 100 percent in the GHG analysis. Do you know why that is?

MR. BAKER: I think it's indicative of the confusion that's swirling around this issue. Even with respect to the three utilities in the state, you have an assumed 80 percent overlap factor for Edison and PG&E, whereas for San Diego we assumed it was 100 percent overlap.

And it has very much to do with the way in which goals are set with respect to the best understanding at the time of what the potential is and the variety in the IOU service territories. And so that's why we're here, is to understand this issue better.

MR. TUTT: Okay.

MR. BAKER: Thank you.

PRESIDING MEMBER BYRON: Good. Ms. Marshall, who else do we have in this section?

MS. MARSHALL: I imagine we have other parties that would want to respond to the next set of questions. NRDC or any of the utilities.

MS. ETTENSON: Where would you prefer I stand?

PRESIDING MEMBER BYRON: Either one.

MS. ETTENSON: I don't have a

presentation; I'm just going to -- my name is Lara Ettenson with NRDC. And I want to first thank the opportunity for being here and commenting on this. I think this is a very important issue and we're very pleased that we can be a part of it. And also like to commend the staff for all their hard work so far on this issue. This has been long in coming, and I'm looking forward to working with everybody moving forward.

In particular, for the first question, in terms of how the demand forecasts are used, and if there are issues associated. A number of agencies are using the demand forecast and using them differently.

In particular, CARB uses the demand forecast to inform their business-as-usual greenhouse gas emissions which will ultimately tell us how much reduction we'll have to have in emissions under AB-32.

And concurrently the CPUC and CEC are also looking at different GHG reduction strategies and regulations to address these emissions that we need to reduce. So, it's imperative that these are consistent in order to have the most accurate analysis going on in the state.

And similarly, the demand forecast is used, as you heard, for the long-term procurement planning, but also the publicly owned utilities are also using this demand forecast in their AB-2021 goal setting.

And currently there are a number of discrepancies. As you've heard, there's a discrepancy already just in the different definitions of committed and uncommitted.

But I think the most notable discrepancy, as I've mentioned before, is with the E-3 methodology where for the CPUC/CEC GHG modeling the E-3 methodology assumes that 100 percent of the uncommitted efficiency, and that is the future efficiency, is actually embedded in the demand forecast.

So this means that during their reference case they don't net out any more energy efficiency; and we see that there'll be a load growth of about 1.2 percent. Whereas, when the CEC analyzes the goal of 100 percent all cost effective energy efficiency, they don't assume that any of this future energy efficiency is embedded. And we see that future efficiency on top of the forecast will show that our load growth

will be a negative load growth.

And so that highlights very clearly that the assumptions that go into these are very different among the different agencies. And that we would request that the CEC take a lead in coordinating with these different agencies to see what the best assumptions could be to make the most consistent analyses across all of the agencies.

So in regards to question number two, again we appreciate the staff's effort to clearly delineate the different amount of historical and future energy efficiency. The future being those impacts from the different 09-11 programs and further, as well as the standards updates.

In addition to that we think that there needs to be even more clear delineation of this data. And I understand the difficulty in understanding these parallel tracks of 09-11 when those have not yet been approved. But I think that it is important to have some sort of future look so that we can do some analysis planning. Especially with the CARB analysis being undertaken right now.

In addition, I don't believe there's any

discussion of the natural gas embedded efficiency in this forecast. And I think that is something that should also be addressed moving forward.

And my understanding, as well, is that this model was created some time ago without the same understanding of the legislation and the requirements that we are using this forecast for today. And I would request that we look closer to see if this needs to be reevaluated.

And we look forward to working with the staff in order to better understand the current model and to see what types of improvements can be upon this model. And then ultimately if we do believe there needs to be a new model, we understand that is a huge undertaking, and would take longer than this timeframe that we're talking about in the interim.

However, I do think that, again, in the interim it's very important to have a common set of assumptions that we can use across all of the agencies so that, as was mentioned before, we can, at the very least, minimize the discrepancies on our way to figuring out how best to identify all of the issues and how to address them.

So, in regards to question number three,

all of these different entities using the demand forecast would benefit from more clearly delineated impact of both historical and projected. And in particular, I think, especially given that California is undertaking a monumental effort in AB-32, that it is imperative that we have a very clear understanding of how much emissions we really do need to reduce; and exactly how the strategies and upcoming regulations that are going to be recommended by PUC and CEC really impact those emissions.

And lastly, in terms of timeline, NRDC will defer to the other agencies. However, as we've seen, the sooner the better. And in particular, CARB is going to present their scoping plan at the end of the year, and I believe they have a draft this summer.

So if we can do an interim, you know, sometime at the end of April with the understanding that we'll need a longer term solution going forward.

Thank you very much for the opportunity and I'll answer any questions you have.

PRESIDING MEMBER BYRON: Any clarifying questions for Ms. Ettenson?

MR. GORIN: Can I make a comment?

PRESIDING MEMBER BYRON: Go right ahead.

MR. GORIN: This is Tom Gorin. These models may be old, but a lot of what we are talking about now was done in ER 93 and ER 96. They are DSM volumes from that time period.

So we're sort of going back in the historical period to where we were 10 or 12 years ago, to revisit these issues. And they need to be revisited.

But we've ignored them in the past. From 1998 until recently they've been largely ignored because of restructuring and other things. But we're going back to the kind of analysis that we used to do 10 or 15 years ago.

PRESIDING MEMBER BYRON: Ms. Ettenson, thank you for your comments, thank you for your written comments. Tim.

MR. TUTT: Just one question. Ms. Ettenson, this is the second time, just from Mr. Baker's presentation, that we talked about a discrepancy between the definition of committed and uncommitted conservation.

The definition I heard that Mr. Baker used at the PUC to me in my understanding seems

exactly like what the CEC uses. I'd just like to get clarification from staff as to whether there is a discrepancy there.

MS. MARSHALL: Yeah, the discrepancy is not with respect to our specific definition of efficiency. It's in how various effects in the forecast are attributed. Whether they're attributed to standards or price effects or programs. That's really the issue we're trying to resolve.

MR. TUTT: So you have the same program scope for committed --

MS. MARSHALL: Was through 2008 was committed, as well.

MR. TUTT: Thank you.

PRESIDING MEMBER BYRON: Anyone else in this section, parties responding to workshop questions?

We have someone over on the left side. I saw a hand go up.

MS. MARSHALL: Either Rick or Herb.

MR. EMMRICH: Good afternoon. My name is Herb Emmrich; I'm the Demand Forecast Manager for Southern California Gas Company, San Diego Gas and Electric.

PRESIDING MEMBER BYRON: Would you mind coming a little bit more forward to the microphone.

MS. tenHOPE: Are we jumping ahead to the forecasting, utility forecasting or --

PRESIDING MEMBER BYRON: You're just responding to questions, correct?

MR. EMMRICH: Actually I was going to do both.

MS. MARSHALL: Yeah, I think some of the utilities have sort of organized their comments in response to all the questions together. So, you can either do them before or after staff --

PRESIDING MEMBER BYRON: No, that's great. Thanks for the clarification. We may have some others that may wish to respond -- so please identify yourself again.

MR. EMMRICH: My name is Herb Emmrich; I'm the Demand Forecasting Manager with Southern California Gas Company, San Diego Gas and Electric.

And we do all the demand forecasts, short-term and long-term, for the utilities. And, of course, include a energy efficiency component in those forecasts.

So I was going to go through quickly on what our demand forecast models look like; how they compare with the CEC's models.

And I want to first of all express my appreciation to the CEC Staff for the great job they've done in the past on the IEPR processes; and also their assistance currently in our California gas support process. We really appreciate those efforts.

Our end-use forecasts are divided by several types. We have for the residential market, for commercial/industrial market. And, of course, we have models for electric generation.

We have equipment replacement lives that are in the models that are similar to the CEC. We vintage all the equipment types. And when equipment is replaced, it's replaced by whatever the efficiency standard requirement is. And that's incorporated in the model and we vintage that year by year.

New customers, of course, are added also year by year, and whatever equipment they have has to meet the efficiency standards.

With the end-use models, the demand for gas over a given time interval is the sum of, you

know, the demand for new customers, demand from existing customers, and customers replace equipment. That is all taken into account.

And this cohort vintaging process is very important. That makes sure that whatever effects that are coming to be because of the energy efficiency standards are captured.

The end-use models allow us to segment markets because the important thing of energy efficiency is to know which market to go after; to look at what equipment is old so we can replace the equipment costs effectively. That seems to be, I think, a little bit overlooked in some of the modeling processes.

And, of course, the model tracks usage by customer equipment characteristics, and the utilization rate and the fuel efficiency of that equipment, and the fuel choices.

This is just a quick look at the residential market, single family, multifamily, large means more than four units; and small less than four units. And we have a whole lot of sub-metered units. These are mobile home parks and so on.

Under core commercial market we have 14

segments, as you can see. There's a large array that goes by -- code. We track that customer usage by -- code. And use a forecast, economic forecast by each segment to see what happens out in time.

Same thing with the industrial market; has 11 segments. And we track each and every one of those markets. Southern California is the largest industrial area in the United States. And we have a multitude of industries. Although most of the high energy use indices have left southern California. We do have a great number of remaining small- and medium-sized companies.

For each end-use fuel type and efficiency level the analyst inputs saturation of the equipment. And this is where we have a lot of help from the CEC with the advanced survey and the industrial survey and the commercial survey. That input data is vital and absolutely necessary if you're going to use end-use models. And as that equipment is updated, then the models will be more accurate and more useful.

And this is all the different types of end uses that are looked at and the inputs that are needed.

The gas usage, you have a base year that you calibrate to. That base year has to be weather-adjusted for gas use to make sure that you capture all the past energy efficiencies. And then you go forward with your forecast.

The model has a choice element. I don't know if the CEC model has a choice element or not. In other words, there's an evaluation of end uses, either gas or electric, high efficiency, medium efficiency, that the customer can select based on the forecast of gas prices, of electricity prices, and the cost of equipment out in time.

What the utilities, of course, do in the energy efficiency programs is buy down the cost of buying more efficient equipment. And that is the main way that people are motivated to actually make equipment change-outs, especially in the industrial sector.

Like all models, you know, we have forecasts of economic loads. We have construction forecasts. By the way, construction is way down; I'm sure people are aware of that. But we have a 35 percent decline in building permits, so the growth that we have projected just two, three years ago, has been cut basically by a third.

The model solves optimally, based on pure economics, what the customer choice will be out in time. And we believe it provides a good forecast.

I already mentioned that we need the input from the surveys, the RASS survey, the CEUS survey, IEUS survey. These are very important to us. We add conditional demand analysis to these because we identify the customers, and through conditional demand analysis are able to evaluate what kind of usage there is based on family size and building type, et cetera.

This are the inputs that are required by the designated market segments. And this is standard, I believe, or very similar to what the CEC model is.

What are the benefits of using end-use models. The equipment is not static. The choices out there, the model gives you choices. And you can evaluate what kind of an energy efficiency program you need to cost effectively increase equipment replacement. Ultimately the long-term effect is by having more efficient equipment, not just higher prices.

In order to evaluate, you know, you have

to hold other things constant. I think the CEC does the same as we do. There may be a little bit difference in decay rates, in meter growth, and we'll work with staff to coordinate those inputs.

What do we use this stuff for? I mean we use it for our utility filings with the CPUC, inputs to the Energy Commission. We use the CEC forecast to reconcile our forecast. It's one of the major forecasts that we look at to compare our results with the CEC, and of course, EIA and other independent private-sector companies.

We use it for internal consistency checks by running different kinds of scenarios. One of the things I would advice the CEC to do is to do more scenario analysis, you know. Just listening to the comments by the previous speaker, and reading her comments, constantly looking for accuracy.

There's no accuracy in forecasts. What we give you is a 50/50 probability forecast. That's a point estimate. That means there's a 50 percent chance it'll be higher, and 50 percent change it will be lower.

To constantly try to come up with a model that will be, you know, accurate, like we

can actually predict the future, is kind of silly.

You know, at this point in time we should put that aside and work on scenarios to see what the range of possible outcomes can be. There's no such thing as an accurate forecast, you know, it's all probablistic.

The outlooks that we present, that the CEC presents, is looked at by everybody. It's looked at by the utilities, by industry, by investors and so on. It is a baseline forecast that is very valuable. And it needs to be out there.

We certainly look at it and we work as hard as we can with the staff to try to understand what they're doing and try to give them input on our side.

What would you like to see? One of the things that we're having extreme problems with is getting the load that the nonutility served entities are requiring, the gas load served off of Kern-Mojave, or other interstate pipelines. Also what their electric output is, what their forecasts are. We have no input to that.

We're trying to estimate our own forecasts for California gas support, but how do

we get that information. If the CEC can provide that kind of information and get them to participate in this process, that would be extremely helpful.

As far as the data sources, we'd like the staff to clearly identify what the data sources are; what they're based on; what the history is. So that data is valuable. We can do our own regression analysis and so on in order to use that in our forecasting efforts.

Overall there are some inconsistencies between staff and the utilities which has been mentioned already. We assume that the CPUC will continue to fund energy efficiency programs throughout my lifetime. I'm an old guy, so that may not be that long, but we don't believe that just because you have a three-year funding program that somehow that's the end of the input on energy efficiency. That doesn't make any sense.

We're mandated over a ten-year period to meet energy efficiency goals. And the program cycle is funded every three years. But even after that ten-year program, or the ten-year goals, we assume that the funding level will continue. Because energy efficiency certainly makes sense

for society, as a whole.

Anyway, to sort of close up, the value of the energy efficiency -- I mean the end-use models is that it's got a choice element. It is not pre-programmed econometrically. It actually has a choice of choosing high efficiency and so on. And we can use that to evaluate programs.

As stated, we do our forecast and then we are required to subtract out 100 percent of the state mandated targets. So, once you calibrate the model to the actual year at hand, in our case it'll be the year 2007, then we go forward and do our forecast. And then subtract out the goals that are for 2008 and beyond.

That's all I have. I'm open for questions or comments. And, again, I appreciate the opportunity to present our views. Thank you.

MR. TUTT: Hello, Herb. I want to go back to the last point you made where you said you subtracted 100 percent of the state mandated targets from the demand forecast.

I understood from earlier presentations that at least in the long-term procurement proceeding those goals and targets are considered to be embedded in San Diego's load forecast. Are

you talking just for Southern California Gas?

MR. EMMRICH: I'm just talking for Southern California Gas, on the gas side. And for San Diego on the gas side. Not the electric side.

MR. TUTT: Okay.

MR. EMMRICH: I believe there's somebody here from the electric side? We have two people here from the electric side that can answer that question.

Greg, if you --

MR. KATSAPIS: Do you want me to answer it now?

MR. TUTT: Now or later, doesn't matter.

PRESIDING MEMBER BYRON: Any other questions? Well, thank you, Mr. Emmrich.

MR. EMMRICH: Thank you.

MS. MARSHALL: So we'll hear from the San Diego electric side now. Greg Katsapis.

MR. KATSAPIS: I'll make mine brief. My name is Greg Katsapis for the SDG&E electric side.

Just wanted to touch upon a couple brief points. Basically looking at peak load, talking about energy efficiency, talking about how a forecast is being used.

Forecasting. You have models, you have

inputs and you have results. Staff uses end-use models; we use a blend of both, the other utility use econometric, it doesn't matter. It doesn't matter. A model's a model. It's just a relationship between variables. Forecast is variables, and you have a forecast.

Forecast results. They have to make sense, okay. You have to take the piece of paper and do a sniff test and make sure it makes sense. And I think that's where there's some confusion.

This graph here is SDG&E's peak per capita, okay. Over the last 25 years. Basically it's an upward sloping line. And we, as forecasters, have to explain that. If you can explain history, you have a reasonable model, you can explain the forecast by using a set of assumptions.

Okay, where do those assumptions come from? Various places. You notice a big drop during the energy crisis. We had a 200 percent increase in prices, okay. Applying normal elasticity, some of that makes sense.

Let's take a quick look at what we were looking at, what Tom looks at. This is one of Tom's favorite graphs, peak per capita. I put it

in log format, okay.

If you convert it to logs instead of looking at megawatts on the Y scale, you're now looking at percentages. So you can see this graph goes from 6.85, which is a meaningless number, to say, 7.15. That represents a 30 percent increase, okay.

So, over the last 25 years SDG&E has witnessed a 30 percent increase in peak per capita. We have to explain that within our models.

Now, during this time we had building and appliance standards. During this time we had DSM programs, now called energy efficiency. Whatever we explain in the past we have to explain in the future.

We had about a 15, 20 percent drop during the energy crisis. Since then we've had five years of record growth, 3 percent growth. So, the overall 25-year history SDG&E has witnessed 1.2 percent peak per capita growth over a 25-year period.

So I just draw a trend line through that 25-year history and that's what it looks like, the blue line.

Pre-crisis we were growing at 1.7 percent per year. Post-crisis, 3 percent per year for five years in a row.

Let's look at the forecast. The yellow line is mine and the black dotted is Tom's. For the first five years we're virtually identical, okay. For -- this is how Tom's label his forecast in form 1.4.

However, they both look very low relative to history. So we have a lot of explaining to do. What could substantially change between history, because it's not economic growth because that's taken out by divided by population, so you have building and appliance standards, you have energy efficiency, you have prices, you have productivity, et cetera, et cetera.

We're forecasting .6 percent growth per year and Tom has .3 percent per year. That's a far cry from 1.2 percent, and it's certainly a far cry from 3 percent. So, let's move forward.

The main concern here is double counting energy efficiency. And that's certainly a concern for resource planning. So when we use a forecast we have to make sure that we're using it appropriately, and we're considering what is

embedded in a forecast, whether or not that forecast is appropriate for resource planning.

So, here I just took the same graph and the black line is once again using the CEC's forecast from form 1.4. And what a lot of folks want to do is take incremental energy efficiency, take the cumulative impacts of those first year impacts and subtract them out.

When you do that, you end up with the red line. Okay, so you have negative .7 growth, negative .7 growth per year for the next 12 years. I don't think too many resource planners want to plan their system to that. But that's what we were faced with throughout this procurement process.

Future energy efficiency, as the gentleman from the PUC mentioned, is already embedded in the forecast, okay. Is it 10 percent, is it 100 percent, is it 150 percent? That becomes the question, because that's going to be the adder or subtracter to the forecast.

Number one, common sense, okay. If the forecast did not have energy efficiency embedded in it to some extent you would see a forecast that looked like a hockey stick. It would go along at

X percent and then it would jump up, okay.

As an example, I just took the first year impacts for year 2008 and put them back into the forecast. If we had a forecast that did not have energy efficiency embedded in it, we would see, for SDG&E, about 1 percent, and the same thing for all three utilities combined. We would see about a 1 percent increase, maybe a 1.25 percent increase in growth.

You don't see that in the forecast. You see constant 1.5 percent growth throughout the forecast, whether it's committed or uncommitted. So common sense dictates that energy efficiency is embedded, as the PUC dictated, 80 percent for Edison and PG&E, 100 percent for SDG&E.

With respect to SDG&E, those embedded numbers were based on target goals which were 118 percent of maximum achievable. So essentially we have 118 percent embedded in the forecast.

We have to be reasonable here with respect to how folks use this forecast. Energy efficiency should be treated the same as implied historically. More than double counting is possible, it's probable. And the cumulative impacts need to be discounted over time.

I think no one would take incremental annual impacts historically and say that's what's embedded in the model right now. Over time they are replaced by standards. I got an air conditioning rebate. I bought an air conditioner; three years later it became the standard. That energy efficiency program impact should be zero. It's now attributed to standards. So you can triple count some of these concepts.

I think staff recognizes in their very nice effort to try to substantiate some of these goals. For example, from 2005 to 2008 these goals were explicitly accounted for in the model for three consecutive years if I added up the incremental committed goals, they were 185 megawatts for SDG&E.

Over that same time period the total impact of conservation energy savings was 107 megawatts. So there's definitely some discounting. We have to make sure that whatever we apply historically, whatever makes sense, we have to apply that in the future, as well.

Because it all goes back to this graph. If we had all these impacts historically, and we have 1.2 percent growth, and I have trouble

explaining why we're down to .6 percent growth, I sure as heck will have a heck of a hard time explaining negative .7.

So, in the long-term procurement plan last time we were okay because the Commission -- the CPUC recognized this. But I think going forward we need to make it very clear how we're going to treat these goals. And as Mike mentioned earlier, what is feasible, what is not feasible.

California Solar Initiative, if you look at the CEC's forecast, what's the statewide goal, 3000 megawatts or something like that? If you look at their forecast they embedded about 400 megawatts ten years from now.

So Tom does this -- I mean that's what a forecaster does. He has to apply reason. I think the same thing and most important thing here is from energy efficiency, because the magnitude is so large, we have to apply that in the future, as well.

That's all for me. Any questions?

PRESIDING MEMBER BYRON: Any questions?

MS. MARSHALL: Okay. Shall we hear from PG&E?

PRESIDING MEMBER BYRON: Thank you, Mr.

Katsapis, Katsapis.

MR. KATSAPIS: Close enough, close enough.

PRESIDING MEMBER BYRON: Thank you.

MR. ASLIN: My name is Richard Aslin and I'm representing Pacific Gas and Electric Company today. And I would like to just say thank you to the Commission and to the staff for all the work that they've done in the past and today and going forward on trying to get a better understanding of what electricity demand in California is likely to be going forward. Because I think that is an important issue.

We've seen a lot of slides, and unfortunately I have a few more, so hope you can hang in there for a few more slides.

PRESIDING MEMBER BYRON: We welcome --

MR. ASLIN: Okay, glad to hear that. What I think I'll do is I'll give my responses to the first three questions, and then I'll just step down. And then when we get back to answering question number 4 later, then I can just answer that question at that point.

But the main themes of the responses to the first three questions, one will be, as was

pointed out by others, that we do need to try to sort this out in the fairly near term, because we do have a scoping memo for the 2008 long-term procurement plan at the Public Utilities Commission. And that requests that this be sorted out. And the 2009 IEPR cycle is going to be starting up pretty soon. And then we have the 2010 long-term procurement plan.

Which is really, I think for PG&E, one of the major goals is to get this sorted out so that when we go into the 2010 long-term procurement plan, we can have a better understanding of what's actually in the forecast.

Because PG&E does support the IEPR process, and we'd like to use the IEPR forecast as much as possible in everything that we're doing for the long-term planning.

PRESIDING MEMBER BYRON: I do not know the dates for your long-term procurement plan. Do you?

MR. ASLIN: The --

PRESIDING MEMBER BYRON: You said it needs to be sorted out before the 09 IEPR/2010 LTPP. Do you know the date before when that would be?

MR. ASLIN: When we would be filing the 2010 long-term procurement plan? I don't know the exact date.

MR. BAKER: I can speak to that.

PRESIDING MEMBER BYRON: You know what, it would be great if you'd come to a microphone and that way we'd be able to capture -- just press the green button there and we're in business.

MR. BAKER: Can you hear me?

PRESIDING MEMBER BYRON: Yes.

MR. BAKER: So, as set forth in the order instituting rulemaking for the 2008 LTPP proceeding, the CPUC anticipates a scoping memo for the 2010 LTPP proceeding in which plans will be submitted, considered and approved.

And that scoping memo would be in April 2009. And we would anticipate plans being submitted by September of 2009. With adoption of the plans in 2010.

PRESIDING MEMBER BYRON: Thank you.

MR. ASLIN: Another theme that I want to try to address in the responses to the first three questions is that this current modeling convention around energy efficiency with committed and uncommitted periods in the forecast, it might be a

little bit outdated. And it might be really causing more confusion than it's being helpful.

The third thing is, and it really, from my point of view, this is all about looking forward, but I do feel like it might be good to revisit this issue of the 2007 IEPR.

And that is that from PG&E's point of view, and I have a couple of pictures that I can show you on this later, but our point of view is that if really 100 percent of the energy efficiency targets are already embedded in the forecast, that, you know, 80 percent was certainly better than 60 percent, which was certainly better than zero. But we feel pretty strongly that it is actually 100 percent.

I would also like to have people think about a couple of things. One is that this issue of things that are embedded in the demand forecast is not, in my mind, really limited to energy efficiency.

I think there's an issue also around self generation and how much self generation is actually embedded in the demand forecast. We struggled with that actually quite a bit also in the long-term procurement plan.

It wasn't as high profile an issue as energy efficiency, but when we looked at the growth in self generation that's shown in the tables in the California energy demand forecast, what we saw was a pretty low incremental increase in self generation.

We had a much larger increase in self generation in our own forecast. But we felt compelled, because of the scoping memo from the Public Utilities Commission, to just subtract off the difference between those two things.

And I think that might have also resulted in the final forecast being lower than what might be reasonable going forward. So it's not just energy efficiency; there's other issues about what's embedded in the forecast beyond that.

And finally, I would like people to think about this issue, and I think Herb actually brought this up a little bit. But, I think we do really need scenarios or we need some sort of idea of what the dispersion around this expected value is.

Because I'm not convinced that expected value forecasting or expected value planning is really the right standard for the electric market.

Seems to be a lot more downside to being short on resources than there is to being a little bit over on resources. So that's something I think people should think about, whether that expected value is really what's needed.

So the first question was how are the demand forecasts used in other venues. And here I have a slide right after this, but essentially almost every venue where the forecast is used, what is really used is what I'm going to call the mitigated forecast. And what I think in the CEC terminology might now be the managed forecast for what, in the NRDC or Air Resources Board terminology, might be called the business-as-usual forecast.

But what people really want to see in the forecast and what they're really using it for is what demand is actually going to be. That's what people are really using it for.

And right now we have this sort of hybrid situation which is a hold-over from a previous period of time where the forecast is broken up into part of it being the managed or mitigated part, the business-as-usual part, that's the so-called committed period. And the other

part of the forecast is this other thing, it's the unmitigated demand forecast; it's the unmanaged demand; and it's the not business-as-usual.

And those two things are very hard to deal with when you're trying to use the forecast.

So I just tried to just briefly list out a few of the uses. Obviously generation planning is a use. Transmission planning, distribution planning, financial and rate planning. I can tell you that I've fielded calls from people on Wall Street asking what's California demand forecast, you know, for the next 10 or 15 years.

There's the greenhouse gas emissions planning. And Herb actually reminded me that there's also the California Gas Report, where the electric demand forecast is used to then generate the gas burns from natural gas fired generation plants over the next 10 years, which is used to plan for the facilities that will be needed to serve that market going forward.

I can't think of a single one of these planning exercises where this hybrid forecast is really needed. But in every single one of these forecasts I can see that the mitigated forecast is needed.

And there's a few uses where it would be nice to have both. It definitely would be nice to have both in generation planning. That way we could run scenarios, we could look at, you know, what's the effects of having a little bit more energy efficiency and so on and so forth.

Also in greenhouse gas planning it might be very important to know what's already embedded in there.

But, for the most part, people who are using the forecast, especially in transmission planning, distribution planning, financial planning, rate planning and really in generation planning, what's needed is really the mitigated forecasting.

I'm just trying to drive home this point that this modeling convention of having this hybrid part of the forecast being mitigated, part of the forecast being unmitigated, is not really serving a useful purpose as far as I can see.

And, Lynn, just put you on the spot here, but wasn't there one IEPR when we didn't use that modeling convention?

MS. MARSHALL: We used a longer definition of committed because there really

wasn't any firm program planning cycle in place at that time. It was 2003. And so we just assumed program funding held constant.

But as Greg pointed out, you know, it didn't have much effect on the forecast one way or the other, which we'll talk about later, why actually reducing, you know, netting out those uncommitted programs we do think that a lot of those effects are overlapping with other assumptions in our models.

MR. ASLIN: So, moving along to question two. So question two is asking what sort of additional information or analysis would parties like to see. And from PG&E's point of view I think the staff did a really good job in the California energy demand in the revised part of it in sort of stripping out for the residential and the commercial classes what was embedded in those models and then projected forward.

But there was a couple of classes, industrial and ag, where I didn't really see that same analysis. And at least historically industrial, and to some extent ag, have been areas where we have seen a lot of energy efficiency savings.

So what I would like to see is that California energy demand analysis extended to cover all of the classes, and not just residential and commercial.

My understanding was that the industrial and the ag were done via an econometric model and not an end-use model.

MS. MARSHALL: Yeah, they're not end-use models which makes it more difficult. We'll talk about that a little bit later.

MR. ASLIN: And then the second issue just is again around one thing I would really like to see is a similar type of analysis done on how much self generation is actually embedded in the current forecast. So I think going forward that could become as big an issue as energy efficiency.

And then finally, as other people have mentioned, we would like to see scenarios. I think in the 2005 IEPR there was a low, a base and a high scenario. And then in the 2007 IEPR there was just the expected case. So I think -- the high scenario was really useful in the 2005 IEPR. I think a lot of people really used that to say, okay, here's what demand could potentially be.

And my understanding was, or my

recollection of it was that many of the planning exercises that we did with the 2005 IEPR were based on the high growth forecast. So I'd like to see that.

I'd like to see some sort of just idea of what the error variance is on the forecast going forward, the standard forecast error or something like that. Just to give us an idea of what is the dispersion of this forecast. That's very useful.

PRESIDING MEMBER BYRON: I think we got the answer earlier. It's 50 percent chance of being above the point and 50 percent below.

MR. ASLIN: Yes. That's what I say here on the end of three, there. Planning to the expected value is planning to be short 50 percent of the time. So I'm not sure that's the right value proposition.

PRESIDING MEMBER BYRON: Good point.

MR. ASLIN: This is just taking some things from the California energy demand analysis that was done by staff, and then adding to it an estimate of at least historically what we think might be embedded with respect to industrial and ag.

So the first two, the 265 megawatts for residential, that's from the staff's analysis. The 485 megawatts for commercial, that's from staff's analysis. This is all cumulative during this period 2009 to 2013.

And historically our industrial and ag savings from CEE programs have been in the range of 100 megawatts. So just putting that together for a five-year period, that's 500 megawatts. If you total those up you get 1250 megawatts. And if you look at the CPUC adopted targets for PG&E for that same time period, it's 1220 megawatts. So, that leads us to believe that maybe the 80 percent assumption that was used in the long-term procurement plan was a little conservative.

PRESIDING MEMBER BYRON: Excuse me. The values starting with 265, are those derived, or are those --

MR. ASLIN: Those are taken from table 14. If you just --

PRESIDING MEMBER BYRON: Thank you.

MR. ASLIN: Okay. I guess just to answer question three, how would this additional information and analysis be used.

It would allow us to understand the

forecast much better; and to understand how we needed to adjust the forecast for the various uses that it's put to. That's the main thing.

As I mentioned before, and I have a picture on this which I think will be good, because it touches on a few things that people have said earlier, also. But, you know, we started out in the last long-term procurement plan with the 2005 IEPR and with the statement in that that no effects from programs in the uncommitted period were included in the forecast. Okay, so zero it was; no mitigation at all.

And then because we wanted to use the staff's forecast in the long-term procurement plan consistent with the scoping memo, we got together with Lynn and Tom and we started to work through the issues, and we came up with an idea that, yeah, you know, it probably isn't zero. It's probably something -- there's probably something in there. And then ultimately we decided, well, we're going to go with 60 percent.

And then later, during the course of the 2007 IEPR, which took place during the same period of time that the long-term procurement plan was going on, we realized, you know what, it's

probably bigger than 60 percent. In fact, for San Diego Gas and Electric it could be 100 percent.

And then ultimately it was the Public Utilities Commission that just said, okay, we're going to say it's 80 percent. But, again, we actually think it's 100 percent. But 80 percent, it's better than zero and it's better than 60 percent. But 100 percent is what we think it should be.

And so what I tried to do on this slide was just capture that graphically. So this is kind of what I call the evolution of a guesstimate.

(Laughter.)

MR. ASLIN: Okay. So, the green line, that's kind of where we started. So if you took the view that the forecast had no mitigation in it at all, and then you subtracted off all the target savings, you would get this green line. It's very similar to what Greg showed on his graph. Essentially you get negative growth over this time horizon.

And my understanding from attending the workshops on the scenario analysis was that this green line is sort of what was picked up in that

scenario analysis work. And then there was a statement in the scenario analysis report that said that if we adopted targets at the level of what was economically efficient -- I believe that's the statement but people can correct me if they have a better understanding of that -- that we would get to this situation where we would essentially have zero load growth by the time we got to 2015 or 2020.

But that was based on an erroneous understanding of what was actually embedded in the base forecast. So, we go from this first assumption of the guess, which was zero, to the next assumption of the guess, which is the red line, which is 60 percent mitigated.

The light blue line is hard to see, sorry. There's a light blue line between the red and the dark blue. That's the 80 percent mitigation. So, that's essentially what the CPUC decided at the end of the day.

The dark blue line is what you get if you assume 100 percent mitigation. And the yellow line is what you get when you compare that to PG&E's forecast. And that's another reason why PG&E feels that the forecast is already 100

percent mitigated. But that's looking backward and we're looking forward here.

I put this graph on here because Greg had said something about the hockey stick. So this is sort of the hockey stick. Essentially what you would expect is if the forecast was really 100 percent unmitigated during the uncommitted period you'd expect to see that the growth in the uncommitted period was significantly higher than it was during the committed period.

It's a little hard to see here because the committed period is so small. It's just those first two years, 2007 and 2008. But that's the hockey stick. That's what you would expect to see if it was really not mitigated. You would expect to see this yellow and green line at the top, and then as you assume different levels of mitigation you start to move down.

And that's all I have for questions one, two and three. So, I do really appreciate everyone's time and I know that was a lot of slides. So, I apologize.

I'd be happy to take a question or --

PRESIDING MEMBER BYRON: Questions? Thank you, Mr. Aslin.

MS. MARSHALL: We have Edison here, also; so maybe we should hear from them next.

MR. GILLIES: Good afternoon. I'm John Gillies; I'm representing Southern California Edison. I'm in the long-term demand forecasting group. I appreciate the opportunity to be here this afternoon to take part in this interesting discussion.

PRESIDING MEMBER BYRON: Mr. Gillies, do we have hard copies of your presentation?

MR. GILLIES: I believe I left a pile outside, yes.

MS. MARSHALL: We'll get you some, yes.

PRESIDING MEMBER BYRON: Please proceed. Please proceed. We'll get copies.

MR. GILLIES: I'm sorry you didn't get them distributed.

I thought I'd spend some time on discussing how we incorporate and deal with energy efficiency in our forecasting techniques and also I'd like to discuss a little bit about the distinction between utility-sponsored energy savings programs and similar effects that come from mandated appliance standards.

I'll also spend a bit of time with

responses to the questions that were posed.

In our particular way of dealing with modeling we include an explicit representation of energy savings within our econometric approach. Our analysts in our utility programs group gives us estimates of past and future energy savings by category. And we combine this various information into or we kind of rearrange it into customer class categories and expand it into monthly frequency, which is the time frequency we use for our modeling.

So, we have two dependent variables on the left-hand side, which is the observed or recorded consumption, and the energy that would have taken place, or energy consumption that would have taken place if our own programs had not have occurred.

So our thinking is is that this type of energy, the energy that might have occurred if our programs didn't exist, is influenced by the same type of variables, economic, weather, et cetera, that the recorded consumption is. And I've listed those in kind of a short format there. There's cooling degree days, heating degree days, pricing, -- effect, and billing days.

This allows us to create forecasts both of we're calling it unmanaged, and managed forecasts within the context of the same modeling exercise. And having an explicit representation of the impacts of our own programs allows a little bit finer distinction in our model estimation between similar impacts that are coming from government-mandated appliance efficiency standards.

Let me move right on to this chart one on page 4. So here -- you've seen a couple of charts similar to this. This is kilowatt hours per customer in our residential customer class. And it shows history and forecast for both the managed and unmanaged aspects of consumption.

So, if the blue line shows that if the programs did not exist on the right-hand side of the vertical line you would have seen or would expect to see residential consumption or customer growing at about .8 to .7 percent per year over that forecast period.

But the impact of programs is to essentially flatten that out, or leave it relatively flat over the entire forecast period. Now, that's just energy consumption per customer.

But we also have customer additions, as well. So we're going to get growth from those customers. And we expect that to be about 1.1, 1.2 percent per year.

So, EE in the forecast period, it's important to say, includes both the committed and uncommitted. And that's our established way of forecasting. We don't make it a distinction for internal purposes between the committed portion of EE and the uncommitted.

What about the impact of the current and future building and appliance efficiency standards. We do sympathize with the CEC in attempting to separate standards from utility-sponsored EE. That is, it's difficult because utility-sponsored programs are directed towards accelerating the introduction of new efficient appliances. So it's difficult to recognize sometimes which impact is working.

The problem is is that in our approach we don't have an explicit representation of appliance stocks. That's one aspect of perhaps where end-use modeling is more useful in trying to separate out the effect of appliance efficiency standards. But there is possibly some ways that

you could attempt to incorporate it.

I looked at some data from the Energy Information Administration and they do keep estimates and projections of appliance efficiency over time for various appliances. And I've graphed some of them here.

On the left-hand side I didn't -- I forgot to put in titles on the left-hand side, but on the left-hand side are the heat pumps and the central air conditioner. And they are relevant for the red and the blue line. The green line is the electric water heat.

Now, these indexes could be used in the climate modeling to explicitly address also appliance standards. They're fairly, as you can see, there's a fairly steady increase year over year.

Here's another one of building shell efficiency index. This is going in the other direction, downwards, sloping. But it actually has the same impact. That is it's an improving efficiency standard.

I tried something like this with an index as an additional variable, being composed of some of the EIA standards. But it doesn't work

too well on a stand-alone basis because it looks like just another trending variable. And tends to be highly correlated with some other variables, even the cooling and heating degree days.

You could do something like I've suggested in the next statement where you could condition your cooling and heating degree day variables and perhaps your price index with an efficiency index of the type that I showed before. But it doesn't make a lot of difference to the estimates.

Now, I want to thank the CEC Staff because you provided us with some additional detail on end uses for our service area by customer class and such. And that might provide some better weighting in order to get the right kind of combined index for all these different appliances. So I'm going to have another go at that.

In any case, so what we're left with is that the standards, mandated standards are subsumed in the estimates and impact of a lot of the other variables that are left in the model like weather and income, et cetera.

And this works fairly well as long as

the appliance efficiency index from mandated standards are continuing at a fairly constant rate over time. As long as there's not any sort of abrupt transition, the past or the future, we can say that the forecast isn't going to go too far astray.

I was mentioning a lot of our own programs are directed towards enhancing the effect of mandated standards. And this chart shows that area to some degree.

Now, this is residential program energy savings by end use with a 2006 start. And it includes both committed and uncommitted program savings. But it excludes new construction.

And --

ASSOCIATE MEMBER PFANNENSTIEL: Could you just help me understand this graphic. For example, just take refrigeration. Explain what I'm supposed to be seeing from 2006 to 2008 to 2012.

MR. GILLIES: You're seeing cumulative energy savings in the residential sector from programs that are directed towards these end uses.

ASSOCIATE MEMBER PFANNENSTIEL: I see. So, it has nothing to do with the overall

efficiency increases of refrigerators in the inventory that people are going to buy, but rather it says that people who are using -- taking advantage of utility programs --

MR. GILLIES: Yes.

ASSOCIATE MEMBER PFANNENSTIEL: -- are buying more efficient refrigerators each of these, in these timeframes.

MR. GILLIES: Yes.

ASSOCIATE MEMBER PFANNENSTIEL: And this is a cumulative effect of --

MR. GILLIES: A cumulative effect. It's incentives to replace older efficiency with newer efficiency appliances, mainly within our existing customer base.

PRESIDING MEMBER BYRON: So this is the cumulative megawatt hour savings.

MR. GILLIES: Yeah.

PRESIDING MEMBER BYRON: Okay. Thank you.

ASSOCIATE MEMBER PFANNENSTIEL: Thank you.

MR. GILLIES: My main point was that the programs are directed, in a sense, to areas where there's the most efficiency gains to be made. And

those are in the lighting and refrigeration areas. And a lot less in electric water heating, for example. Whereas in the graph you saw before where there wasn't a lot of gains to be made in electric water heating appliances. They've already reached their technical potential, so to speak.

Historically, utility program contributions to energy efficiency savings was estimated to be approximately equal to that of standards. I say that in terms of what we saw in previous CEC Staff report done in April 03, where the estimate of utility programs was about equal to the estimate of building standards and appliance standards. And that's for, I believe, all three IOUs, the period up to 2001.

We've been discussing that to some extent here in the more recent fall California energy demand update. And it looks like now that the utility programs saving contribution is estimated to be only about 10 percent of savings.

We've done our own estimates again of the industrial building and appliance standards.

ASSOCIATE MEMBER PFANNENSTIEL: And why is that? I mean what's the big change in the --

about half to being 10 percent?

MR. GILLIES: I believe it has to do with the amount of overlap that's now being recognized.

ASSOCIATE MEMBER PFANNENSTIEL: Seems like this is kind of key --

MR. GILLIES: Yes, all right.

MS. MARSHALL: In the older graph the utility program savings were the total -- they were what was reported by the utilities. And in that graph you notice there's no price effects.

In the newer graph we're presenting impacts in a way that's consistent with our forecast. And there's -- the utility impacts that are reported are only those that we feel are truly incremental to the standards and price impacts.

So, they're much lower. The total impacts are about the same. It's really an attribution question of how we're reporting it. The newer chart that he's showing is based on the conservation quantification analysis from our forecast; the older data was simply using the utility-reported impacts.

MR. GILLIES: So, Lynn, it's safe to say that they were two different methods --

MS. MARSHALL: Yeah.

MR. GILLIES: -- used to create these two slides.

MS. MARSHALL: Yes.

ASSOCIATE MEMBER PFANNENSTIEL: Yeah, I got that.

MS. MARSHALL: We'll come back to this topic during the staff report.

MR. GILLIES: All right, thanks very much for your help.

Yeah, it is difficult to estimate the impact of standards, mandated standards in our models. It's not their impact is ignored, they just get subsumed in other variables.

And if you remember in the first chart, as happened in San Diego, it's also happened in our service area. And that is we saw a fairly significant increase in residential and commercial consumption per customer in the 2002 to 2005 period, a significant run-up.

You know, the impact of standards in our models is there, but it just lessens to some extent. The increase we saw was curved, or brought down a little bit because of the impact of standards than it would have been otherwise.

And one of the things that's occurred in that period was a significant change -- well, it's not a significant change, but some very important changes in the way our customer base is distributed. We've seen a shift in customers into our hotter climate zones. We've seen an increase in average housing size. And those two effects have come together in that the larger homes are being built in the hotter climate zones. So this has put pressure on both energy and demand growth, particularly in the 02/05 period.

Questions for the workshop. The first part, in our own internal activity our forecasts are used for financial and resource planning. And obviously for LTPP and ERA filings and compliance filings for external purposes.

Like the other utilities, we do see a potential for confusion between whether a forecast is managed only, or is an unmanaged version.

For our own purposes we do deduct uncommitted EE. But for -- again, for external purposes and when instructed to do so, we won't deduct the uncommitted EE from the forecast.

It does seem that the CEC recognizes uncommitted energy efficiency as a supply

resource. So, to some extent, its legitimacy has been established. But since it's really an extension of committed energy efficiency, that is savings that's occurring at the customer meter, it seems to me it's more properly placed into the energy forecast rather than on the supply side.

The discussion I've done on how we treat energy efficiency and standards in our own modeling does suggest that end-use models that the CEC uses, for example, are probably better suited to an explicit representation of the impact of standards. It's putting actual quantity of gigawatt hours or megawatts on the impact of standards.

We do agree with the CEC that there is a significant overlap. Staff has suggested in the 80 to 90 percent range. And other utilities here suggest that it would be more than that, in the 90 to 100 percent range. So I think we need to establish, perhaps, a type of methodology that's applied consistently to all of the utilities, and come up with an overlap figure if that's what's required that we're all satisfied with.

In the 06 LTPP the overlap percentage used to reduce the uncommitted EE was used in the

resource plan, and we expect future estimates of overlap be used in the same way.

In response to question four, I did spend some time on it. We estimated EE in our own models.

Any further questions?

PRESIDING MEMBER BYRON: Questions from -- Mr. Gillies, thank you.

MR. GILLIES: I thank you very much.

MS. MARSHALL: Are there any other utilities or any other parties that want to make comments at this point? Okay.

Yeah, sure, go ahead.

MR. BURT: I am Bob Burt, Insulation Contractors. I did not file in advance comment paper because I did not think I was going to do anything but take notes. But in listening I have found that there's a comment I should make.

And that is that there seems to be little recognition in the course of he afternoon that there is a potential for tremendous increase in the available energy efficiency in this state.

First of all, you note that all of the curves on demand go up. That does not meet very well with our AB-32 target, which requires either

down or else replacement of existing greenhouse gas sources with nonsources.

Well, all I can say is anybody brave enough to try to put in a nuclear power plant in California can look forward to a ten years; five years of conflict, if successful, and another five years of construction.

So we're not going to meet the AB-32 targets by reducing our conventional sources. Which leads me to say in that case if you compare the cost of sequestering CO2 and moving it to a place where it can be disposed of, even recognizing that pressurized CO2 is valuable for recovering oil from old reservoirs, you still look at a tremendous cost compared to any current estimates of the cost of energy efficiency, which, of course, power not generated does not generate any greenhouse gases.

So, that leads me to believe that there is a likelihood for much higher cost/benefit numbers for energy efficiency. And that, of course, means that there's a whole lot more potential.

If anyone wants an example of a couple of very large serious potentials I'll cite that,

for example, virtually every house built in California before 1970 had empty walls. Very little has been done to meet that problem because of the fact that when you drill holes in those walls to install insulation, the ugly repairs require a paint job. And that removes the energy cost/benefit.

I would suggest that with the larger cost/benefit that we should see from looking at the AB-32 potential, we could provide for a per-square-foot allowance for painting the walls that are insulated.

And the reason I call for a per-square-foot allowance is that all of us learned when we observed the zip program that there's a tremendous willingness in California to use contracts for fraud. So I don't say pay for a paint contract.

Second, there's a very large potential for cogeneration. Nearly every large point source heat in California, and there are thousands of them, is a potential for cogeneration.

Now, all this obviously would call for very large, upfront investment. And I don't feel that we should try to stick that on the ratepayers. I think that if California is serious

about AB-32, and I agree that it's possible they're not when people look at the cost, then we should do a bond issue. And that automatically reduces, it makes more cost/benefit available because I can tell you in my past life I did a lot of cost/benefit studies.

You cut that interest rate very much, it makes a spectacular difference on long-term projects. And if we use the interest rate for our low-interest loans that the state can make, compared to, as I was told the other day, the common rate used today by utilities for cost/benefit for energy efficiency is around 8 percent. That would again authorize a whale of a lot more energy efficiency.

So, putting those all together I can say that there is -- we have a good likelihood that much of the energy, the AB-32 target can be met with energy efficiency with all of the possibilities that it can be increased.

My other point is very minor, and that is that I would call attention to something that I believe was first raised by Ms. George in one of the previous PUC hearings, and that is that energy efficiency is pretty much localized.

And that means that if it's studied on the basis of its actual locations, then the fact that demand which is met by energy efficiency in place obviously eliminates the line loss involved there. But it also reduces at least some of our problems on improving the grid.

So that I agree that that would add a considerable extra effort to attempting to do our demand forecast. But, if, in fact, we're serious I think it should be considered. We are neglecting a measurement of energy efficiency value which, if you remember that line losses for a utility run around 5 percent, has considerable reality.

With that I withdraw. Since I made this up while I was sitting here listening, you obviously don't have to endure any slides.

(Laughter.)

MR. BURT: Do you have any questions for me?

ASSOCIATE MEMBER PFANNENSTIEL: Thank you.

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

MS. MARSHALL: I'm Lynn Marshall with

the demand analysis office, one --

MR. TUTT: Lynn, before you start, there's another comment from the audience.

MS. MARSHALL: Oh, sorry.

MS. TURNBULL: I'm Jane Turnbull from the League of Women Voters. And I also was not planning to say anything.

But I thought that Chairman Pfannenstiel's question about refrigerators over a period of years was an important question because it implied that the efficiency rate of refrigerators was more or less static.

I think one of the things that I learned last week in the demand response hearing is that the utility industry is no longer a static industry. There is an opportunity for a lot of dynamic components. And that the rate of change is potentially a lot greater than we had anticipated.

I thought Dr. Jaske's questions at the beginning were really very mind expanding. And the answers to those should go a long way.

You know, granted the industry remains capital intensive overall, but the components of the industry that are less capital intensive are

also in the really dynamic component of overall industry change.

Therefore, I think there's an opportunity to learn from some of the companies that are developing new products in our green technology industries. Because as they have to develop business plans, the rate they see as a rate of change in their industries as a very rapid one. And they have to plan for it.

So I think the utilities, rather than looking at a projected straight line growth into the future, based upon percentages in past years, really might benefit for looking at the opportunities for more dynamic growth industries in the green technology industry we're looking at.

Thanks.

PRESIDING MEMBER BYRON: Thank you, Ms. Turnbull.

MR. GLICK: Thank you for the opportunity to comment. My name is Ken Glick and I represent today Northern Star Natural Gas. Very brief comments. Most of you who know me are probably thankful that they're brief.

Two points. One, natural gas demand forecasting, under the state's alternative

transportation fuels plan there's a heavy reliance on natural gas through compressed natural gas or LNG as a transportation fuel for offroad vehicles. And if all those targets in the plan are met that would be a demand of approximately 65 bcf a day -- annually, for natural gas.

That should be put into the forecasting model. And when you bring that subject area to the fore, it also presents opportunities for efficiency gains probably through an organization like CARB, through mandating some type of performance standards on those engines. it would reduce consumption.

So that's a scenario in which the state might realize efficiency gains in that particular venue.

Second thing was the omission of gas-fired natural gas generation demand figures. We know from historic trends that that's the fastest growing, or the steepest demand curve for natural gas consumption in the state. So, omitting that understates the state's growth demand for gas.

Also, there's efficiency gains that are realized on the electric generation side that would have a ripple effect when you consider their

impact on natural gas-fired electric generation.

When you don't forecast that into your energy demand picture, you also don't forecast or create the opportunity to model the efficiency gains that would follow through on the natural gas side.

So I would just encourage the Energy Commission in the future to incorporate those two subject areas into its demand forecasting model. And then also to recognize in the scenario modeling end-use modeling of efficiency gain potentials that those be explored, as well.

The utility should be given recognition for the efficiency gains, not only that they acquire through, on the electric side, but the ripple effect as that plays out on the gas demand.

Thank you very much for your time.

ASSOCIATE MEMBER PFANNENSTIEL: Thank you.

PRESIDING MEMBER BYRON: Thank you, Mr. Glick.

MS. MARSHALL: Okay. I'm Lynn Marshall; I'm going to talk about our demand forecasting methods, the basic model structures and assumptions, especially as they pertain to how we

model standards, programs; how price effects factor into our forecast.

And then we'll talk about the conservation quantification analysis we did for our last forecast, and present some of those results. And talk a little bit about the implications of how our modeling structure affects how we would want to develop a methodology for doing uncommitted forecasts or uncommitted scenarios going forward.

So this is the big picture of our overall modeling system. We have a number of energy sector models. We have economic drivers for each of those. We have future rate assumptions and we model each of those energy using sectors.

We model annual energy consumption, both natural gas and electricity, for each of these sectors, residential, commercial, industrial, ag. We also have communication and utilities.

That energy forecast, the annual electricity forecast then drives our peak forecast. So we take the energy sector forecast results and calibrate them to actual for weather, to actual recorded consumption. We do some

external modeling adjustments.

That is run through our peak model, which adjusts for hourly temperatures and actual recorded peaks. And that gives us our hourly load forecast.

So, we're going to talk in more detail about the residential and commercial and industrial sectors in particular.

So these are all the different sector models. The residential and commercial models are what you would call true end-use models. So they are doing a backcast starting from the mid 70s, and modeling consumption at an end-use and building type level.

So that allows us to do the kind of analysis to explicitly quantify the effects of standards over time.

The industrial model has some end-use modeling detail in it, but it does not do a backcast. So it's harder to do the kind of standards impact quantification that we can do with the res and commercial.

Our ag forecast is econometric, and generally the other smaller sectors are some combination of econometric or trend analysis

methods.

So what we mean by end-use forecasting we're talking about a process that uses energy. So when we talk about the cooling end use, that represents the composite effects of all of the assumptions we've made about building characteristics, shell, operating hours for a particular age of building, and a particular building type for whether perhaps it's a home or whether it's multifamily home.

So, our commercial forecast, as I said, we're starting off in the mid 70s. We have assumptions about what was the floor space stock at that time; what was the stock of different types of appliances and saturations of end uses in different building types. And we're decaying those over time and based on our economic forecast, adding new stock.

And then over time we're also modeling building standards and we have actual prices and so here's our basic -- the basic energy use equation. The end-use efficiency or the end-use intensity of a particular end use times the rate at which it's used. And you multiply that to the percentage of floor space to which it applies,

which would be the amount of existing floor space that's occupied.

So what drives that end-use efficiency. It's a function of price, the rate of replacement of old equipment, the assumptions we've made about the impacts of various iterations of standards, and also the rate of compliance with the standards. So we start off with very low compliance in the first year and we ramp up to 75 percent. For modeling all of these end-use intensity trends relative to the base year to 1977.

The utilization, the second term there, varies in response to a short-term elasticity. So last year's utilization times price elasticity effect.

So this shows the decay of -- example of a decay assumption that we've used. Starting off with these floor stock estimates, equipment type estimates. We make an assumption about the mean life, and we're decaying them over time.

When they get decayed they get replaced with whatever the current level of efficiency is. And why does that matter? That directly translates into our model into when a standards

effect or a price effect takes place.

So if we have shorter lifetimes than the conservation effects occur in our backcast they don't show up on our forecast. If they were longer lifetime it can actually lower the forecast because we're replacing those equipment in the future period and we'd have lower.

So this is one of the challenges in modeling and in comparing our results to assumptions about program impacts is understanding the replacement effects that are occurring in our model versus a measure impact forecast that's assuming measures are replaced in response to some utility incentive.

ASSOCIATE MEMBER PFANNENSTIEL: Lynn, when you replace an appliance, how do you determine what the energy usage would be of the new appliance that you put in?

MS. MARSHALL: It's based on the vintage of the building. So we're tracking -- we're starting off at the beginning. We've got like a matrix of floor stock and equipment. And it's all got a year attached to it.

ASSOCIATE MEMBER PFANNENSTIEL: Right.

MS. MARSHALL: So, if it's ten years

old, gets replaced in a certain year, whatever the appliance standard is, or equipment standard, building standard is, in that year --

ASSOCIATE MEMBER PFANNENSTIEL: But going forward, how do you know what it's going to be, going forward?

MS. MARSHALL: Oh, we don't make any -- we model all the past building standards up to 2005, and there's no ratcheting down of efficiency after 2005.

So for our forecast, the -- well, let me talk about -- the only new standard is 05, okay. Let me talk about how this effect is modeled in the forecast.

So, the end use intensity, how do we calculate that. When you get to particular floor spaces being decayed. We actually do two calculations. One is the standards effect. We have assumptions from the standards impacts analysis of what the lower EUI would be for say cooling use per square foot. We do that calculation; that's actually standards, and that's the second formula, factoring in a compliance rate.

The first formula is the efficiency

choice purely from a price effect, just applying our price elasticity. We compare those two. We choose the greater impact, so the lower one is the one with the greater conservation impact. So we're choosing either the standards or the price effect, whichever is bigger.

There are probably other ways you could do that, attribution, but, you know, that's the way we do it. So that's important to understand when you look at the conservation quantification results.

PRESIDING MEMBER BYRON: Ms. Marshall, is this a new slide not in our packet?

MS. MARSHALL: It's not a new slide.

MS. tenHOPE: I think you changed the title. It was commercial sector in the handout.

PRESIDING MEMBER BYRON: Okay.

MS. MARSHALL: You may have -- yeah, there should be a new set up there that should match. You were supposed to get new binders with the new slides. Sorry if you didn't get them. So these are a little cleaned up compared to the last version.

And I'd just point out, we have two sets of price elasticities in the model. We have this

efficiency price elasticity, and then we also have the utilization price elasticity. So in effect there's a short-run effect and a longer run effect. In this set, this persists over time.

And then once an end use moves to a new level of efficiency it stays there for the rest of the forecast until it decays again, and then it would move to the next standard level.

And these are the price elasticities for both electricity and gas. And this model, let me just point out, everything I've said generally applies to both electricity and natural gas. And we did this quantification analysis all for electricity and gas, even though we have tended to do more discussion of the electricity.

So, here are -- these are for the most recent set of appliance standards. These were the end uses affected. So we're making these adjustments relative to our base year intensities.

And I'll just say a little bit about those. Were developed back in the early 90s based on building simulation models done by LBNL. So they're a pretty complex analysis factoring in shell characteristics and operating patterns.

For the most recent set of standards we

haven't been able to do that analysis, so we've been using the standards office impact assessment. And we also haven't factored in some of the secondary effects of the standards as we work to incorporate the results of the new commercial end use survey into our forecast. We'll hopefully get back to having our -- being able to do our own building simulations and have more robust analysis of these effects.

So, here's an illustration for the San Diego area of the impacts of the standards, how the EUIs are declining over time.

So, for example, for lighting you can see the big decrease start, there was a big drop in the 98 standards. And a lesser effect to the 05 standards.

And then on cooling and ventilation the big impact was back in 84; more recent standards have smaller reductions in the end use intensity.

So that's the standards effect. We also, for modeling program effects, programs are handled one of three ways. There are a few that are quantified internal to the commercial model. Some are modeled externally in the summary model so it's just kind of subtracted off at the end,

and as part of the calibration process.

And others, we've essentially concluded that the price effect and standards effects are already reflecting the impacts of those programs. So they're not accounted for. I'll come back to that and give some examples of why we think that.

But let me go back to the first, the way we would model a program, and this is an older program that's actually still accounted for in the commercial model. It's an old load management program, an audit program.

And so the impacts were based on both utility reported savings for the audit and ex-post studies of audit impacts. And then an energy savings per square foot for each end use was calculated. And then we did the same kind of calculation of calculating the program effect directly and comparing it to the price effect. And only choosing one of those, choosing the greater. So that's the concept for how you would explicitly model program impacts internal to the model. You always want to make sure that you're not double counting with price effects.

So, here's the --

MS. tenHOPE: Can I ask a clarification

on this number three?

MS. MARSHALL: Yes.

MS. tenHOPE: So, if someone receives a rebate it's assumed to go into price effects and not into utility programs?

MS. MARSHALL: Well, yo have to look at, as Mike talked about earlier, you really have to look at individual programs and the individual assumptions in the models.

So it's not just that no programs ever have any effects on the forecast. But as we've looked at them over time, that's generally the way things have shaken out. The new construction where they're exceeding the current building and appliance standards, yeah, that's clearly an incremental impact to the forecast.

But a lot of -- and let me -- I'll move on to the next --

MS. tenHOPE: So, but it's --

MS. MARSHALL: -- slides to give an example of why we have done the analysis, and come to the conclusion that to subtract those incremental effects of rebate programs will be double counting.

MS. tenHOPE: Okay, and that also goes

back to a change that Chairman Pfannenstiel asked about before, that why those -- I can't remember, it was SCE's slide 10 and 11 that there's big change between historic and current, is that you're characterizing those programs differently now than you were?

MS. MARSHALL: We're not characterizing them differently. There was a graph, the older graph had reported program savings, total reported program savings. And that's accurate data as far as it goes.

What you don't want to do is stack that up with also, and our standards effects, and maybe our price effects, and subtract that all from the demand forecast. They're not consistent.

So, the newer graph we were presenting the total impacts in a way that was all consistent with our forecast.

So, let me go through the rest -- a couple more slides on the conservation quantification and --

MR. TUTT: Lynn, can I also clarify this last one?

MS. MARSHALL: Um-hum.

MR. TUTT: Rebates for retrofit

activities.

MS. MARSHALL: Um-hum.

MR. TUTT: And as an example can we look at rebates for something that's fairly common in utility programs, compact fluorescent lights.

In the residential model is there a lighting end use where you would take the price of that into account there?

MS. MARSHALL: Do you want to -- I'll let --

MR. GORIN: No.

MR. TUTT: So, how does that retrofit rebate then be accounted for if there were price effect in the residential model?

MR. GORIN: Or --

MR. TUTT: Compact fluorescent.

MS. MARSHALL: Or simply replacement. So, it's not necessarily price.

MR. GORIN: We haven't explicitly covered compact fluorescent lights in the residential sector yet.

MR. TUTT: But there are utility rebate programs that give rebates for compact fluorescent lights, or buy down the cost of those. Would those be covered in this item three?

MS. MARSHALL: Yes.

MR. TUTT: I'm not sure I understand how you do that if --

MS. MARSHALL: Why don't we go --

MR. TUTT: -- end use for that.

MS. MARSHALL: Okay. Maybe we can go through -- let me finish the commercial sector and then Tom's going to get into the residential. Because I have a couple of examples from the commercial.

MR. TUTT: Okay.

MS. MARSHALL: And then maybe Tom can get into this. Address that, as part of explaining those residential structure.

Okay, so the conservation quantification analysis. What we did was a series of model runs where we're backing out all the prices, one by one, prices, each vintage of standards and -- building and appliance standards, the programs embedded in the forecast, okay.

So, in this graph the blue area is our base forecast. The top line represents unmanaged forecast with all of the price and conservation effects backed out.

And this just shows the same effect with

each of the individual vintages of standards and programs shown. And as you can see, the price effects are quite large.

And as I talked about, there's a little -- remember the comparison of the price effect and the standards effects, there are probably other ways you could do that attribution. But this is why the price effects are so large.

So, what do you do with that analysis. Well, we broke it out, we pulled out some of the end-use level detail. And if we take the incremental conservation effects, this example is for commercial lighting in the San Diego area, it's possible to start doing some comparisons, for example, with the measure level impacts and the potential studies. So this is from the 2006 potential study.

You could also do this with utility program plans if you have them at sufficient level of detail, for many -- until 2006 we didn't have anything like end-use level detail in the utility program plan. So it really limited the extent of the analysis we could do.

So, I don't want to make too much of the precise numbers because this is sort of a rough

comparison. We're comparing to their existing commercial current incentive scenario. And I've taken, for this example, the 92 to 2001 standards effects to try to exclude the effects from new buildings.

But what you can see is while the potential scenario that current incentives case, kind of a basecase, is higher than us in the near term, when you get out very many years our effects are much larger.

So, the lighting conservation effects in there, in our commercial sector, are quite large. And this is, I think, just illustrates for you why we have come to the conclusion that we don't then want to also subtract, go ahead and subtract lighting impacts on top of that.

Now, as Mike Jaske talked about earlier, we do want to develop a, you know,--

PRESIDING MEMBER BYRON: We didn't catch that one at all.

MS. MARSHALL: I lose you some -- okay, where did I lose you?

PRESIDING MEMBER BYRON: Well, I think it best that you try and explain to us this figure. My pages aren't numbered. The one that

you have up there now.

MS. MARSHALL: Okay.

PRESIDING MEMBER BYRON: What's going on? Why they cross and why you don't want to back out the impacts in the staff --

MS. MARSHALL: Okay. So I am comparing two things, okay. The purple area are effects from the staff forecast model, incremental conservation effects from 2003.

And I took out the 05 standards because I wanted to compare it just with existing commercial building case from the -- model. I left out some of the older standards because we could probably conclude that those represent measures that are in the potential study, either.

And as I said, this is just a rough comparison. You really want to drill down into the measure level in more detail. But we're just illustrating the orders of magnitude here. Okay?

So, --

ASSOCIATE MEMBER PFANNENSTIEL: This is commercial lighting.

MS. MARSHALL: Commercial lighting, existing buildings.

ASSOCIATE MEMBER PFANNENSTIEL: So the

purple area says that the amount of commercial lighting in each of these years --

MS. MARSHALL: The conservation impact.

ASSOCIATE MEMBER PFANNENSTIEL: On commercial lighting.

MS. MARSHALL: Yes.

ASSOCIATE MEMBER PFANNENSTIEL: In each of these years.

MS. MARSHALL: Yeah.

ASSOCIATE MEMBER PFANNENSTIEL: From the staff forecast unadjusted by what? I mean, is it adjusted by anything? What does the staff forecast include in it?

MS. MARSHALL: Well, these are the conservation quantification results from the forecast when we back out -- this is the sum of the price and the -- the pricing standards effects from the staff forecast for those years. Okay.

So, we're comparing that to the projected impacts from the current incentives case in the 2006 potential study. Just to give an indication of, since those are what the utilities generally built -- they're roughly consistent with the utility program plans.

So what we're trying --

ASSOCIATE MEMBER PFANNENSTIEL: Okay, then talk about the potential study.

MS. MARSHALL: What?

ASSOCIATE MEMBER PFANNENSTIEL: The potential study, it's a point in time, and it is the technical potential of --

MS. MARSHALL: This --

ASSOCIATE MEMBER PFANNENSTIEL: -- commercial lighting --

MS. MARSHALL: This particular one is the potential, the scenario under current incentives. Like if you held, basically it's -- if you held funding constant what would the incremental savings from that level of measure penetration be.

MR. TUTT: And when they do that study don't they take into account the fact that there are already in place 2001 standards?

MS. MARSHALL: Not in that study. These are just gross. In the new one that they are going to produce, -- get Mike Rufo up here pretty soon, he's going to talk about how they do those studies.

And one of the challenges for us since utilities use our forecast, but they use measure

penetration assumptions that are developed in something like the potential study.

The challenge -- a big part of it is simply reconciling those two different methodologies and finding a way that we can start to compare these.

So this is just making that type of comparison simply at the end-use level.

MR. TUTT: So, Lynn, one last question. Can you explain why in this chart and some of your others the initial estimate of conservation impacts is negative in your model?

MS. MARSHALL: Price effects. San Diego, as I mentioned, the skyrocketing price effects in 2001/2. So in this timeframe prices have come down, so there's a utilization.

So, yeah, it's negative in that.

MR. TUTT: Presumably there were positive impacts for standards in that timeframe, and they were offset by negative impacts for price effect?

MS. MARSHALL: Yeah, they're pretty small. I mean, taking increments off 2003. So those are pretty small numbers out there.

I was trying to get it on the same

timeframe that the potential study case.

But I think what this shows when we talked about the decay curves and how we have replacement occurring in our model automatically as a function of buildings and appliances being replaced, that's picking up a lot of conservation effects automatically that can, well, maybe, you know, if it happens a year earlier it's attributed to an efficiency program.

But overall, if you look over the whole forecast horizon, we have comparable levels of impacts for that study. Now, when the new potential study comes out we want to understand how their modeling naturally occurring and do this comparison at a more detailed level.

But I wanted to illustrate sort of the magnitude of the impacts. And this is the same thing for lighting. That are already happening in the staff forecast.

Any more questions on that?

MR. TUTT: It still seems like in comparing these two different numbers, what's still lost or confusing to me is what the basis of that potential study was. Because I could believe that the potential study was looking at impacts

beyond what you're -- or changes in end uses beyond what you're modeling in your --

MS. MARSHALL: Well, it is important to --

MR. TUTT: -- in your model.

MS. MARSHALL: -- look at the specific. It is important to go further and look at the specific measures. And that's where we want to go next. That's part of the game plan for going forward.

On the peak forecast I just want to make one important point. All of the end use energy forecasts that we have been discussing are translated into load shapes at the end use and building type and climate zone level in our forecast.

So, if you have, when programs or standards are targeting specific end uses, those are the end uses reduced on the peak. And they're going to have differential -- you're going to have differential effects on peak depending on which end uses the programs target.

That's why it's so important when we do this type of analysis of an uncommitted forecast or quantifying programs, we need to know some

of -- the program mix or we can't -- we have no basis for, you know, modeling the energy on peak impacts.

And I think we'll let -- unless you have any further questions on this, I'll let Tom talk about the residential sector. Okay.

MR. GORIN: I'm Tom Gorin and I'm going to go over some of these functions in the residential model; and hopefully clear some things up, but maybe muddy the waters a little more, so.

Residential models basically based on households and appliances has a historical stock data, projected stock data, has appliance use for each vintage of house. And for 24 end uses and three housing types.

The basic component is consumption and it's a function of houses in year T, times saturations of appliances in year T, which is equal to the number of appliances in year T times the usage of appliances in that year.

Our households are tracked by year of consumption starting in 1970. This is an example of the decay matrix used for houses. We have an estimate of housing stock in any forecast year by housing, by cohort of house by year built.

This becomes important in tracking houses built under various iterations of the building standards.

We also keep track of new appliances purchased by year of purchase, which serves to keep track of appliance efficiency by year purchased.

The appliance calculation is based on -- the saturation is based on the average saturation for the first year. Starts with information derived from the 1970 census and subsequent appliance survey data provided by the utilities. And most recently, the 2002 RASS data.

The overall saturation in one year is based on the overall saturation of remaining appliances from the previous year times a marginal saturation in which appliances are purchased in both new homes and existing homes that do not have the appliance yet, which came into prominence in the 90s with a lot of retrofit of air conditioning in homes that previously didn't have air conditioning; homes with an appliance that failed in the current year; and homes that have an operating appliance but decided to get a new appliance.

These are -- for some specific end uses these are split by fuel type such as cooking and a few other appliances. And the advantage of looking at these different markets is you can look at different policy measures that will affect some of these marginal saturation markets.

The way we -- these are the major appliances that are affected by the appliance standards, the Energy Commission, refrigerators, freezers, room air conditioners, dishwashers. Both motors and water use, clothes washers and water use and water heaters.

The end uses affected by both building and appliance standards are space heating, central air conditioning and water heating.

We benchmarked our savings estimates to pre-1978 efficiencies, or 1978 is the benchmark year for appliances. Building shell characteristics for building standards are based on pre-75 construction practice.

Savings for heating and cooling actually are a combination of both building shell improvements and appliance improvements. We have -- buildings decay at a much slower rate than the heating and cooling appliances. So, central

air conditioner that's put in first in 1978 in a new house, that's put in again, it would be put in a shell that is effectively at a 1978 level currently, with some caveats.

These are the impacts or reductions relative to the year shown that are used in the model. And way to look at that, frost-free refrigerators in 1960s and 1970s were much less efficient than the base 1978 year where we benchmarked the appliances.

So a refrigerator purchased in 1970 used effectively 30 percent more energy than one purchased in 1978. Ones purchased currently use approximately -- well, ones purchased in 1992 use approximately half of those that were purchased in 1978.

You'll notice that there's an increase for more recent refrigerators. That's due to an assumption that we use in the model that refrigerators are getting larger with more amenities to them.

If the utilities came up with a program that rebated smaller refrigerators with less amenities, that would save a lot more energy than rebating larger refrigerators. So we don't

consider that kind of program in our model.

Basically central air conditioners with 2005 standards are using about half of what they used in 1980, just from the appliance efficiency standards.

The change in electric space heat was an assumption that from 1981 all electric space heat would be heat pump. And prior to that they were electric resistance.

The way we calculate the standards, which may be helpful to explain if you have questions on it. The marginal you see the blue line is -- UEC from 1978 is about 1260 kilowatt hours for each appliance bought in each of those years.

The blue line is the appliances -- the unit energy consumption for appliances purchased in a given year. So, after 1991 or 1990, I guess, the marginal UEC is around 820 for all new appliances.

Using the appliance decay matrix, that produces an average UEC which is the purple line, for the total of all the freezers in that year, in each year. So that's the -- purple line is the stock average.

Now, to calculate the savings from the 1990 appliance standards on freezers, the marginal UEC is held constant at the 1990 level, which is the blue dotted line. That yields the stock average UEC of the fuscia dotted line, or purple, whatever color it is -- I'm color blind, it's okay -- of a higher value, because it's assumed that all new freezers from the forecast period are purchased at a higher efficiency rate.

The difference between those two purple lines is what is attributed to freezers to the 1990 standards savings. So when we attribute savings in the residential model we worked from our baseline forecast backwards, assuming what would happen if nobody ever bought anything that was efficient.

In the building standards we have two, well, this is an explanation of how our housing shell characteristics are modeled. They're modeled from the building standards perspective of 100 percent R-19 insulation in houses, ceiling insulation in houses from 1975 to 1983. After 1983 all houses have R-38. All new construction has R-38 ceiling insulation.

There's also a portion of retrofit of

insulation, both ceiling and wall insulation, that are included in the forecast model so that our assumption from the survey data that we had in the late 70s was that in pre-75 housing 30 percent of PG&E gas-heated homes that have gas central heat had R-19 ceiling insulation already.

But we assume a retrofit over the time period so that by 2018 or actually the year 2000, and it doesn't increase in our current forecast, that 55 percent of those houses now have insulation, R-19 ceiling insulation. And there's an increase in the value of homes with R-30 ceiling insulation, up to 10 percent by 2018.

I would suggest that this would be a overlap with programs that promote ceiling and wall insulation retrofit for older homes. So those are accounted for in the model currently.

PRESIDING MEMBER BYRON: Mr. Gorin, I'm not sure I can tell exactly where we are on our schedule, but I need to ask you if you can pick it up a little.

MR. GORIN: Hurry up, okay. This is just showing how the building standards thermal shell increases reduce consumption over the housing vintages and the similar average and

marginal UECs that are created by that. And you can see that they decrease over time.

The same thing for cooling requirements, a similar continual decrease over time.

Measures that impact water heating are appliance standards, building standards and behavior. Regarding temperature settings and flow-restricting devices. Cold-water washing and water heater blankets. And these are the corresponding, average and marginal UECs for gas water heaters and electric water heaters.

Essentially this was done to try and explain how these savings estimates were derived from the building standards and appliance standards, other conservation programs which are retrofits and market and price savings.

And this is a similar graph that Lynn had for each of the iterations of the building and appliance standards.

MS. tenHOPE: I'm confused. The aggregate conservation impacts seems to show no price savings, or it's so small that whatever that magenta is on the top can't really see --

MR. GORIN: It is small.

MS. tenHOPE: -- a price impact. And

then on the conservation impacts by program, price and market is -- oh, I see, there's two yellows. It's the top yellow is still small. I was seeing the large yellow below.

MR. GORIN: Do you want to talk to that --

MS. MARSHALL: Okay, it's getting late so I'll try and be concise, real concise here, just making a couple points about how we do our industrial sector forecast.

As I said, this is not a true end-use model. It doesn't do a backcast, so we don't have the ability to model changes and consumption over time and try to figure out what's efficiency and what are other effects.

There are some in motors in particular, there are some specific assumptions about motor structure. I'm not going to even get into that, details of the model here, but -- most of the end uses, thermal and other, steam, it's really the energy intensity trend over time is primarily driven by price effects. It's driven by a weighted average of price and electricity, both natural gas and electricity. So we don't have explicit modeling of any efficiency programs or

direct effects in there.

In motors you can do some modeling of motor choice as a function of electricity price; and it calculates a payback period. And there is some movement to higher motor efficiency.

But what we've seen in that forecast model is it doesn't really predict the declines in energy intensity that we actually observe in the industrial sector.

And here is the aggregate of our manufacturing industries in the Edison area. And so you see output, economic drivers increasing; electricity consumption varies with business cycles, but it's, you know, not a big trend up or down.

The electricity, the energy intensity in particular since about the mid 90s has been decreasing and we assume it's going to continue to decrease in the forecast.

Now, is that energy efficiency? Well, it's a lot of things. It's structural change in the industry, change in product mix, productivity improvements. It may be driven in part by environmental regulations. Businesses improving their processes to reduce labor costs. Maybe it's

outsourcing. There's a lot of factors in there.

This is analysis from EIA where they've drived to decompose all of those effects to figure out what's efficiency and what's everything else. And there's a variety of other analyses, statistical analyses, trying to parse this out.

And roughly they find, oh, maybe about half of the decrease in energy intensity that we observe can be explained by structural or other changes versus true efficiency improvements.

So I'll just --

MS. tenHOPE: Is structural the same as price? I mean what would a structural --

MS. MARSHALL: It could be something like an industry shifting to another manufacturing process; or having a different product mix. In food manufacturing there's been an increase in energy intensity because they are making -- instead of selling heads of lettuce, they sell bag lettuce. That's kind of a structural change.

And then there's other changes to the production process like outsourcing the production of an input instead of making it, yourself. So that would appear to be a decrease in energy intensity. It's not energy efficiency because

it's being made in China or someplace. So it could be more energy being used.

So, if we looked at -- just to compare the impacts in our model with these, again making a comparison to -- both the potential study for existing industrial and Edison program plan for 06 to 08 is that light blue line down there.

The impacts that they're projecting are, you know, on the order of a quarter of the decline in energy intensity that we've factored into our forecast.

Now, does that mean that no industrial energy efficiency programs are ever going to reduce demand or should be reduced from our forecast? Not necessarily. You really have to look at these things on an industry-by-industry basis.

So, for example, in our refinery forecast we basically assume that consumption's going to grow at the same rate as capacity, which there's no new refineries, so capacity only grows at about a half-percent a year as they improve their facilities. So there's no efficiency at all in the refinery sector. So if ARB is going to target that sector to change their energy use,

that change would be incremental to the forecast.

On the other hand, here's the semiconductor industry and PG&E. I'd say that's a structural change, right? We went from the -- I don't even know if -- the data in the 80s is really not even comparable to the industry now, I think, it's probably evolved so much.

We have a decline in our -- a gradual decline in our energy use intensity for that forecast. It's consistent, it's a little less than recent trends, but we're assuming that the rate of decrease is going to continue.

So, there's a fair amount of energy efficiency factored in. That effect is larger than the high tech goals PG&E has in their program plan. So that's a sector where you might -- you really have to look at it closely because we probably already have those effects captured.

So, I will stop there. Do you have any questions?

Okay, we would like to --

PRESIDING MEMBER BYRON: Yeah, where do we begin? Go right ahead, we're going to continue.

MS. MARSHALL: Well, let's go -- I've

done a couple of examples comparing our impacts to the potential study, and that's really the methodology we're exploring for resolving this issue going forward, is comparing the assumptions in the staff forecast to the measure level projections that the utilities use to build up their program plans, to try and get them on a consistent basis.

So, we've asked Mike Rufo to come talk a little bit about how those potential studies are done and --

MR. RUFO: Do you want to do that now?

MS. MARSHALL: Yes. 4:00.

MS. tenHOPE: We don't have these presentations, either.

MS. MARSHALL: Me, either.

MS. tenHOPE: Okay.

(Laughter.)

MR. RUFO: The first thing will be an apology.

MS. MARSHALL: Okay.

MR. RUFO: Should I start with my apologies and my other --

MS. MARSHALL: Okay.

MR. RUFO: Yes, I apologize -- Mike Rufo

from ITRON -- for not getting anyone any slides ahead of time. -- get ahead of this workshop as much as I would have liked.

Thank you for the opportunity to say a few words. I probably have more slides than I need. I'm going to skip a bunch of them. I have a general idea, I think, of what you want me to cover. But I'll just try to be flexible. And if I start talking too much about something that's not on-point enough, just please, pipe up and tell me to stop, and I'll move on to another slide.

Where are we at with this schedule? What do you want me to do schedule-wise? I think the original schedule had 4:30.

MS. MARSHALL: Yeah.

MR. RUFO: Okay. So I wanted to thank you guys again for letting me say a few words. And I wanted to thank the CEC Staff for all their work in the forecasting over the years.

As I'll talk about in a minute, I've been doing energy efficiency potential forecasts since 1987. And have worked with the end-use forecasting folks at the CEC many times over those years to get baseline forecasts, saturation data, UECs. And after restructuring it was pretty much

the only information like that available in the industry.

We wouldn't have been able to do the energy efficiency potential studies that we did for the last five or six years without the availability of their data and analysis. So I thank you for that.

So I'm going to mostly talk about the modeling process that's used for the energy efficiency potential studies that have been done over the few years.

Before that I just want to say a couple things about the history of this. I'll try to be brief. And then I have some other observations that are related to what we've been talking about today. And I may not get through all of those, but that's okay. I think the main thing you want me to cover is the second item, right?

So, I think Tom said, I just want to reiterate, we've been at this a long time. I've been doing potential studies for a long time. ITRON is currently working on an update of the 2008 IOU potential study. We just released a draft to the IOUs and to the advisory committee. And that's an update to that 2006 potential study.

There are some differences between the two studies, and I can talk about those today. But I don't know if they're super-critical.

Also involved in updating the DEER study, which is somewhat related to the things we're talking about, because it's another source of estimates for energy savings and load shape impacts that may agree or not with what's embedded in the CEC's analysis.

And we're involved in a project with the PUC to provide some technical analysis to help in the development of energy efficiency goals for the 2012-2020 period.

So, these issues aren't new. We did, in the late 80s and early 90s we were struggling with these same issues of trying to integrate exogenous models of energy efficiency, program impacts with baseline forecasts.

Southern California Edison, in the late 80s and early 90s, had their own technology and use forecasting model called MAPS that ADL, I think, developed. They were using that at the same time they started using SRC's COMPASS model to forecast program impacts.

And they got frustrated with that for

the same reasons that we're here today. And came out with an RFP to hire somebody to build the one-world, holy grail model that would integrate all of this end-use forecasting with program forecasting, as well.

It didn't happen. RAR got hired on that job and built the ASSET model, which I'm going to talk about today, which didn't go all the way to that point. Restructuring came along and sort of everybody dusted themselves off and went on to other things.

But ASSET is a good stand-alone DSM planning model. But it didn't go all the way to that full integration as a forecasting model. Although in theory it could. There are some practical issues associated with whether or not that is really do-able and maintain-able, whether there's enough data to really justify that complex of a modeling effort.

There were also other efforts in the industry. EPRI was doing a lot of work on different kinds of customer adoption models, two-stage models, three-stage models, four-stage models, five-stage models, all kinds of different ways of looking at customer adoption.

And lots of consulting firms were building these kinds of models, as well, to support IRP in those days. And then it all stopped.

So I'm going to talk about ASSET, and a lot of what I'm saying about this ITRON ASSET model, originally developed by RAR -- ITRON acquired RAR about six years ago -- could apply to other similar models in the industry. KEMA has a model called DSM-Assist, which I was involved in developing with Rich Barnes and Fred (inaudible) back in the 90s. It's very analogous in some ways.

There are other models out there. I think SoCalGas uses a Quantech (phonetic) model that has some of these similarities.

But, mostly I guess a key difference in these models, that I may be able to skip 15 slides if I can be concise here, is that the energy efficiency potential models pretty much start from the perspective of what I'm really interested in doing for forecasting energy efficiency potential, program potential, is, you know, I want to look at customer adoption on the margin.

So, what are consumers going to do this

year, next year, the year after when faced with choices of efficiency level A, efficiency level B, or retrofit option X or Y.

And the scope of those studies tends to be narrowly focused on those kinds of issues. What's a consumer going to do in the face of prices that they face, the incremental cost of the measures, the period and savings of the measure; their awareness and knowledge of the measure. Any market barriers that may be associated with the measure. Does the measure provide equivalent levels of energy service.

And these models try to predict whether what share of the customers will adopt the efficiency measure moving forward.

And their scope is kind of limited to whatever that list of measures is. So, you can do a potential study with ten measures, or 100 measures or 1000 measures. Typically those projects are not charged with, you know, and at the same time forecast the entire load over the next 20 years. So that's all been put aside, and there's a more narrow focus.

But there's also a more detailed focus on specific types of technologies and measures

than I would imagine occurs, from my understanding, the CEC models, their end-use intensity models, so they're looking more at the average consumption per home or per square foot for an end use. And looking at the aggregate effect of lots of different measures.

Whereas in the energy efficiency potential models, again you may have 50 or 100 specific measures, all of which have incremental cost estimates, load shapes, per-unit savings, et cetera.

Typically in these studies we estimate, and I think folks are generally familiar with these terms, but they can mean different things in different studies, different authors may have different twists on technical, economic, market program, and actually current potential. We can come back to that in a little bit.

The ASSET model has pretty sophisticated stock accounting, so it looks at a lot of things that you've heard about today from the other forecasters in terms of things have measure lives and they decay and choices are made at the beginning of the measure life, at the end of the measure life.

Types of data that drives these models. Talked about the measure costs, rates, program strategies, what kind of incentives are out there for the different programs, what type of marketing. You know, what's the estimated effect of programs, not just on the incremental cost of a measure, but on the willingness and awareness of consumers to adopt the measure.

And then all that goes into an engine, which I'll talk about in another slide or so, that tries to predict adoption. One of the things that this model has is a calibration, so it tries to calibrate or does calibrate adoptions to a set of adoptions that are known.

So, for the 2006 energy efficiency potential study for the IOUs, the calibration period was the 2004 program period. For the current study that we're just releasing the calibration period was 2004/2005 program cycle. And that, in and of itself, has an effect on the results, because that was a two-year program cycle. And it had a hockey stick.

So, calibrating to 2004 versus calibrating to 2004/2005 produces a different adoption forecast. But the key is that there is a

calibration step of insuring that for the calibration period the model's predicting the same market share of adoptions for the efficiency measures as are observed.

Of course, we don't always have as accurate data as we would like, integral data on those market shares.

So, some of the features of the model. It's event-driven. Let's you replace on burn-out situations. Looks at new construction, looks at retrofit. There are competition groups, so it's not all binary. Just efficient or not efficient. You can have different levels of efficiency.

I think I've covered the multiple run, technical economic, with and without programs. I'll talk about that in a little bit.

Separates out gross and net by calculating what we call naturally occurring, which is maybe becoming more and more of a misnomer.

And also does a benefit/cost test, so you get total resource cost test value out of it. Or rate impact measure test.

I think I'm going to start skipping slides. This slide just kind of illustrates kind

of this funneling concept of potential. I think you guys are probably all familiar with that already, moving from technical potential to economic potential, to a program potential.

And the program potential is going to be a function of the program intensity, the incremental, you know, how big the incentives are, how aggressive the marketing information programs are. And, you know, the extent of market barriers that may be associated with a particular technology.

These are some of the definitions of potential. I think we can just come back to this if you have questions about how technical, economic or market potential was defined in the study, or naturally occurring potential.

One key thing with naturally occurring is that we're currently forecasting naturally occurring kind of on the margin. So it's whether consumers would, are likely to purchase a particular measure today in the absence of programs. It's not, if there had never been programs ever. That's a very different kind of perspective.

MS. tenHOPE: So is naturally occurring

the same as the Commission Staff's price effects?

MR. RUFO: We thought it might be at one point, but I'm not sure. Conceptually I think it's similar. And in terms of what's, you know, the amount of savings being estimated, I don't know.

I think, as Lynn said, reconciling between the potential model estimates and what's in the CEC's forecast, I think it really is a -- kind of have to get the two modeling teams together and go through end use by end use, because I think there are different issues, as they pointed out, for different end uses.

But conceptually, yeah, this naturally occurring is price effects. And it's also, it embeds previous program-induced market effects. So one of my slides today talks about attribution. Attribution is a big deal. Maybe I'll just switch to that quickly.

You know, in the world that we're working, on the PUC IOU side attribution is a huge issue around these utility programs. What fraction of the savings are attributed to recent programs, historic programs, other utility programs, codes and standards, actual market

forces including price effects; from when? from yesterday, from ten years ago, from 20 years ago.

For potential forecasting and goal setting, it's very important; it's a critical element of shareholder incentives; it's a critical task in M&B. You know, it will vary over time, depending on how you define it. It's both a backward and a forward issue. And I think both are important, you know.

Forward is obviously very important from a resource planning point of view. Backwards attribution is kind of important from a policy point of view, because depending on how, you know, attribution is characterized, backwards, that can have a big effect on the perception of energy efficiency and programs.

So, you know, these things matter. They're not easy questions. But, a lot of different conclusions can be drawn about how we do attributions of savings in the past.

You know, it seems that, you know, attribution historically is probably less important to the CEC modelers, I would assume. You know, the forecaster wants to get the overall forecast right. In our environment it has a

really big impact on all of these things that I mentioned above.

So, getting back to your question about is what we're estimating as naturally occurring similar to what they're calling market effects, again, in concept yes. I think in terms of the actual impacts, I just don't know.

But our naturally occurring does also include what I would call historic program induced market effects. So if utility programs have any historic effect on changing product availability, product features, product costs, those are captured in our naturally occurring.

ASSOCIATE MEMBER PFANNENSTIEL: Excuse me, Mike. How about customer information?

MR. RUFO: Yeah.

ASSOCIATE MEMBER PFANNENSTIEL: It seems to me that that's something that, I guess, has to be naturally occurring or market effects, or something out there that would probably have built up over time in California.

MR. RUFO: Yeah, yeah, I think that's a huge -- a huge issue is the awareness and knowledge about energy efficiency. And that's something that, in our models, will have a

baseline forecast of awareness and knowledge levels without any further programs. And then we may have a forecast of how awareness and knowledge may increase as a function of program interventions.

So, conceptually I think, you know, we understand the importance of those things, In the real world we don't have very much empirical data to inform our quantitative assessment of what's the relative effect of programs on awareness and knowledge.

We have some information, but nearly not what we would like. And that's something that we've kind of brought up. I've tried to bring up a lot around evaluation. There tends to be, on the program evaluation side, you just kind of go in after the fact. You try to, you know, look a the effect and folks tend to follow incentives.

But if you look at utility portfolios, big chunks of money in the large C&I sector, half the money is not going to incentives. It's going to all kinds of technical feasibility studies and hand-holding, and trying to convince decisionmakers and stuff.

And we would like to have a more

quantitative, more empirical set of data to help us understand what the relative effect of those interventions are for forecasting purposes, and attribution, in general.

This just shows some of the draft numbers from the 2007 potential study update moving from technical to economic to full incremental cost program market potential all the way down to naturally occurring.

We have three levels of program impacts. One is base, which is continuation of the current incentive levels. The other is full incremental costs. And then the one in the middle is something in between.

MR. TUTT: Mike.

MR. RUFO: Yeah.

MR. TUTT: What's the baseline for these potential estimates? Is there some sort of static amount of degree of appliance holdings that you use as a baseline? How do you account for growth in those and so on?

MR. RUFO: Um-hum. Well, the model, itself, is pretty flexible. But, you know, the actual implementation of the model's, you know, honestly is going to vary a lot by the project

scope; you know, how much effort is going to go into forecast any changes in baseline assumptions about either saturations or floor space or energy service levels.

Generally, we take a lot of the CEC's key drivers, households, floor space, saturation, into our models. But we may not always do that in a fully dynamic way.

We do take codes and standards on the margin, so, you know, anytime there's a known code that comes first in our analysis.

MR. TUTT: So when you say that comes first, so then the naturally occurring potential would be above --

MR. RUFO: Yeah.

MR. TUTT: -- appliance already accounts for that?

MR. RUFO: Yeah, that's a good point. We're not estimating savings in here from existing code. So, SEER 13, for example, doesn't exist. There are no savings in our analysis for SEER 13.

MR. TUTT: All the air conditioner savings are beyond that level.

MR. RUFO: Yeah, exactly. Now, in other cases there are the situations where you take

commercial lighting, utilities and the PUC side of the house is generally taken a lot of commercial lighting as an early replacement phenomenon.

So, full savings are typically claimed for commercial lighting retrofits. And, you know, it's kind of up for discussion, I think, in terms of, you know, how much of say commercial lighting retrofits, you know, ought to be occurring over time through codes and standards. Because there are certain triggers even for commercial retrofits for code.

But that's, I think, a big question in terms of what the compliance rate with that code is. But I think there may be two extreme cases there. The CEC may be taking most of those savings in code over time; the utilities may be claiming most of that is all noncode, and you know, the net present value accelerated, you know, time series analysis might show that it's a combination.

MR. TUTT: Where do those savings show up in the potential analysis?

MR. RUFO: You know, it depends on how the particular measure was modeled. So, for example, for T8s in this study we modeled it both

ways, just because we knew that was kind of an emerging issue.

So in one analysis we take the T8s against the in situ lighting fixtures, so magnetic, 30, 40 watt lamps with magnetic ballast. And we take the full savings.

In another analysis we did, we said first generation T8 electronic ballast was code, essentially. And we took savings incremental to that.

Our model's not really that well set up to do a, you know, five years of full savings, if there's an acceleration effect. And then, you know, ten years of incremental savings.

But that's something that some of us have recommended as a way of looking at some of these savings from a utility attribution point of view of trying to do a remaining useful life analysis when there is an acceleration of when something would have happened otherwise.

So, there are acceleration issues in all this, I think. You know, refrigerator recycling. It's an acceleration, right? Your program's trying to get people to get rid of their old refrigerators. And eventually they're going to

get rid of those things. So there is a need to reconcile those perspectives between the two sets of analyses.

So, I hope I answered your question. I gave you a little bit of a it-depends, but --

One of the things I'm trying to emphasize that we do in our studies more, as other people mentioned this today, the forecasting, use ranges, run scenarios, start trying to put uncertainty bars around some of this stuff because it looks a lot more precise than it is, when we have point estimates.

I don't think I'm going to do that one. I don't know that I need to talk about this. This is just talking about the different types of potential. And we've talked about this already today, naturally occurring.

Utility net. After you take away the naturally occurring; market effect; that should say program-induced market effects. I think we do have to be really careful with our language because we might use terms that sound a lot alike and contextually we might think we're talking about the same thing. But maybe we're not, really.

So we're trying to put the word -- when we're talking about effects that we think might be utility program effects, long term, put the program-induced market effects in front of that to differentiate them from the pure price effects that may be also occurring.

MS. tenHOPE: Is that what the green is?

MR. RUFO: Yeah, just a conceptual. And we have codes and standards --

MR. TUTT: Conceptually that's program-induced market effects?

MR. RUFO: Yes.

MR. TUTT: And the codes and standards is utility programs that eventually would turn into standard savings?

MR. RUFO: Or that could, in this case it was also meant to be future codes and standards, not on-the-book codes and standards.

So, incremental to current, but include future codes and standards from the CEC, say.

I don't know that this one matters. This is more for us. Of course, we struggle with this issue of program-induced market effects. And the fact that, you know, each program has an incremental effect to the previous year, we go out

and we try to measure what would have happened anyways, which would be this line here at the bottom that says no intervention ever.

That's sort of the theoretical naturally occurring. What would have happened if there were never any program interventions in 20 years. We can't observe that line. We'll never be able to observe that line, so we see this other line, which is really kind of, at best, what the market might do if we stopped now. And that embeds these program-induced market effects. But that may or may not be an issue for this meeting here today.

I've already covered this slide on attribution.

I'm getting kind of toward at the end of my time, those are the main points that I have. You know, I have other slides here that I could go through, but I don't know that we should.

I can submit them for posting. Are the presentations going to go with the workshop materials on the website?

MS. MARSHALL: Yeah, they can.

MR. RUFO: So folks can look at them, but I don't want to dig into the last half hour here.

So I think there's a lot that we can do as far as really nuts and bolts trying to reconcile what's in our forecast, what's in the CEC's forecast. And, you know, it's an issue that, you know, we've kind of known was lurking out there for a long time, and you know, brought up a few times.

But I think it's good that it's coming to this point of really trying to roll up the sleeves and look at it. Honestly, when we're doing these potential studies there's just not, you know, time to kind of circle the wagons and try to figure all that stuff out.

I know I may have made certain assumptions when I did the secret surplus study which was used for the first energy saving goal in the CPUC's energy savings goals for 2004 to 2013.

We had a number of charts in that report where we took our naturally occurring, we took our gross program potential estimate. We subtracted our naturally occurring. We called that net. And then we decremented the CEC's load forecast for that net. Just assuming that, yeah, our naturally occurring was the same as what was captured in the market forces.

So, other questions? Again, I don't want to go too far into the remaining time for discussion.

Okay, thank you very much.

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

MS. MARSHALL: Well, that's the end of the comments we prepared. Do you want to open it up for further discussion or comments or --

PRESIDING MEMBER BYRON: Well, I think we may have had some commenters that were either reserving their response to the fourth question, or we may not have heard from.

So, let's make sure we hear back from all the utilities if they haven't weighed in on the fourth question. We have at least one of those, I think.

(Pause.)

MR. ASLIN: Yes, thank you for remembering that. And again, it's Rick Aslin with PG&E.

The fourth question was how do the utilities model the energy efficiency impacts in their own forecasts.

And I can't answer for all the

utilities, but for PG&E we use a regression model. And our underlying assumption is that the regression model is picking up all the things that happened in the historical period. And we'll forecast those trends forward unless otherwise adjusted.

So, it's really -- for us it's a pretty straightforward sort of analysis and it's not any different really than the analysis that we do for other things that have that same feature.

For example, the California Solar Initiative. That wasn't really in the history, so we don't assume that it's going to be projected forward. So we have to make an explicit adjustment to the forecast.

And it's also the case with plug-in hybrids. Those weren't really in the historical period. So when we go to the forecast period we make an adjustment for that.

So what we did with respect to the incremental energy efficiency programs was that we just looked back the last several years and we saw that the kind of program savings that we had been experiencing were in roughly the 200 megawatt per year range.

And we looked at the targets and we saw that those were roughly in the 250 megawatt range. And so we made an explicit adjustment to our forecast, so 50 megawatts per year at the time of the peak.

And that's not really a complicated analysis to do. And I think, you know, a lot of people have brought up this idea of, you know, accuracy in forecasting. And I think that what -- we would love to see more precision in forecasting.

But precision without accuracy is sort of something that we try to avoid because there's certain things we just don't know about the future right now. And it's probably better to just kind of keep it simple, things that can be explained, things that can be understood by just the layperson looking at the forecast. And I think that's beneficial just to have that sort of transparency. Because that's what we're really shooting for.

That's my response to question four.

PRESIDING MEMBER BYRON: Don't you need to do things like adjust for weather and things like that?

MR. ASLIN: Yeah, those were already in the regression model, yeah.

PRESIDING MEMBER BYRON: And I guess we're not talking about very big numbers, then, are we? Difference between 250 and 200 megawatts. Those are --

MR. ASLIN: Well, 50 megawatts -- yeah, 50 megawatts per year over the ten years is 500 megawatts. So, we would view that as being definitely a significant adjustment. Did I not understand your question?

PRESIDING MEMBER BYRON: It's not very much in the general scheme of things. Fifty megawatts in your service territory is how much of your load? We're talking peak here, correct?

MR. ASLIN: Yes. Our load is 20,000 megawatts roughly. And so the incremental adjustment is the 50. We're assuming that the forecast is containing the whole 250 megawatts, but we only need to incrementally adjust for 50, because the regression is already picking up and forecasting forward the 200.

MR. TUTT: And the regression then, looking at the 200 being embedded historically, how far back does that 200 go? Your slide says

recent trends are 200 megawatts. And historically it might have been significantly less?

MR. ASLIN: What we do with our model is we are looking at -- we calibrated it to the last couple of summers of peak demand. So we already have a calibration step in there.

MR. TUTT: Sure.

MR. ASLIN: And so since it's calibrated to the last couple of years, we're actually picking up a lot of the most recent energy efficiency.

It's not a perfect kind of way of doing it. But I think what we're -- our experience with it is that it makes the most sense to do it in that fashion. We end up getting forecasts that are fully mitigated; that have all the features that we think are consistent with the types of programs that are out there with the Energy Action Plan and so on and so forth.

So we are getting reduction in load growth over time. And those reductions are consistent with the kind of increases in the energy efficiency programs that are in the targets.

So we just feel like the whole -- when

you look at it, and you take a couple steps back and you look at what is this forecast that we're producing using this methodology, we think it's a very reasonable forecast in light of the history, in light of things that were occurring in the history and changes that we are anticipating going forward.

MR. TUTT: You use an econometric forecasting method like Edison presented, fairly similar to that, it sounds like.

MR. ASLIN: Yes, we do. Except for, I believe on the Edison case, they did explicitly put the energy efficiency savings and the history on the left-hand side of the equation. And then --

MR. TUTT: You don't do that?

MR. ASLIN: No, we don't put it on the left-hand side. We just subtract off the incremental from the right-hand side.

MR. TUTT: And you judge that incremental sort of by feel for what has been happening most recently?

MR. ASLIN: Yes, that's right. Looking at --

MR. TUTT: -- calibrate to the most

recent year? I mean that calibration really adjusts the line of your forecast up and down. It doesn't necessarily adjust the trend at all, is that correct?

MR. ASLIN: Yes. It's primarily to get the level of the forecast. Correct. With the most recent information that's available.

ASSOCIATE MEMBER PFANNENSTIEL: Rick, I'll ask you this question, but the other utilities can certainly also jump into this.

Now that we've gone through an afternoon of sort of peeling back each of the forecasts that are in front of us, do you feel that you now understand the staff's forecast better? And that now you understand the differences between them? And that perhaps we are closer in reaching some resolution here than we were at 1:00 today?

MR. ASLIN: Well, my overall impression is that during the course of the last several months that we made a lot of progress in coming to a consensus. First of all, that there was a significant amount of overlap. I think that was the first hurdle.

Because in the beginning, in the 2005 IEPR, and then some places still in the language

of the 2007 IEPR it suggests that that is not the case.

But I think that was the big step. And then to get to 60 percent, and then to get to 80 percent, I think that's also a big step.

I guess what's still unclear to me is the industrial sector and ag. If that sort of analysis could be completed, or somebody could just take an educated guess as to how much of the energy efficiency savings that were in that historical period for industrial are implicitly projected forward into the forecast period, I think that would go a long ways.

ASSOCIATE MEMBER PFANNENSTIEL: Okay, thanks. How about the other utilities? Is there -- are there comments? Sort of wrap-up comments on your reaction.

PRESIDING MEMBER BYRON: On your question?

ASSOCIATE MEMBER PFANNENSTIEL: Yeah, on my question of have we made progress here.

MS. JONES: Good afternoon. I'm Jacqueline Jones with Southern California Edison. And I want to say that I appreciate the opportunity to be here and listen to all the

detail of the forecasts.

I know that it's a tremendous job, a tremendous amount of information. And from our perspective, we have learned a lot.

But it also does raise a lot of questions. So, I was hoping that there might be another forum later to be able to possibly exchange information in more detail.

MR. TUTT: Jackie, I have maybe a question for Richard, as well. If he can come back up.

The way I look at this, we've been modeling uncommitted DSM as a resource for some time. And that means not including it in the demand forecast.

And one of the reasons we do that is because it's considered to be a variable thing; that you can have more or less uncommitted DSM.

And to that extent, the amount of it is relatively unknown when you're doing the forecast. You're doing more or less of it.

Now, we have the targets that are out there from the PUC, and that's a relatively known quantity. That's a different story, perhaps.

And the model that staff uses, we

understand there's some overlap embedded in the market and price effects that the model includes as they go through their modeling exercise. And that looks to me like a relatively constant amount. I mean it changes as their price assumptions change from one year forecast to the next. But it's not something that changes dramatically as you're changing DSM program plans.

So, to me that brings up two implications. And the first is that it may be incorrect to look at this overlap question as a percentage amount.

And the second is that more aggressive DSM, more aggressive energy efficiency goals imply less overlap.

Can you comment on those potential implications?

MR. ASLIN: I'll take the second one first. I would agree that for a given forecast, if the energy efficiency targets, for example, were to be increased, then that would imply less overlap relative to those targets.

So there would have to be another incremental adjustment to the forecast, or that increment would be treated as a resource that

would meet demand, that would be over and above the forecast. Yes. I agree with that.

I think that's what we're likely to be facing going forward because it seems pretty likely that the targets will be increased.

With respect to your first question, I really -- just in talking to the several people that I've talked to in the course of preparing this presentation, and also in working with the ISO stakeholder group for transmission planning and on the rate planning exercises and things like that, I really do think that the idea of treating energy efficiency in this so-called uncommitted period as a resource is outdated.

Energy efficiency at this point with the Energy Action Plan, with the Public Utilities Commission's targets decision is essentially a mandate for basecase. So I think for any kind of basecase those targets are going to be in there.

And I think -- I tried to mention this earlier, and I think the NRDC mentioned this earlier, too, that's people's expectation. That's the expectation of users when they pick up this forecast, is that this is a forecast that is the demand that we're most likely to see. That it's

not some -- there's not some modeling convention that they have to work to understand.

It's just, here's the demand; here's what it is. That's how I'm going to use it. And that's how people use it. That's how we're using it in the California gas report, for example.

MS. MARSHALL: Rick, if we do an uncommitted DSM forecast say for the 9 to 11 period, and then possibly for an out period, does that provide what users who want to use the forecast that way, they can take the two and add them together? Does that provide the product they need?

MR. ASLIN: Well, I would say if you're only going to produce one forecast, it should be fully mitigated. But if you're going to produce two forecasts, an unmitigated and a mitigated, then that would be fine, too.

But if it's just going to be one forecast, I really think that what people, when they pick it up, what they're looking for is what is demand going to be. They don't want to have to do that extra bit of work. And many times they won't. They'll just say, well, this is fully mitigated; this is what demand is.

PRESIDING MEMBER BYRON: Mr. Aslin, I had a question that I was kind of holding from your earlier presentation. It's related to this.

You have a preference for a fully mitigated forecast. Do the folks in your energy efficiency group, I guess down on the sixth floor, do they agree with that?

MR. ASLIN: Well, I think we would all like to understand what's in the Commission's current forecast. I don't think the folks in the energy efficiency group, you know, per se, would have any preference.

I know in the electric resource planning or in procurement planning, we have a preference to understand, you know, what it is that we're being asked to use in this long-term procurement plan.

And, in essence, we transform whatever we get into a mitigated forecast.

So maybe I didn't understand fully your question.

PRESIDING MEMBER BYRON: Well, I'm not sure I understand your answer, either.

(Laughter.)

MR. ASLIN: Okay, fair enough.

PRESIDING MEMBER BYRON: Yeah, okay.

Tim, did you have something else you wanted to ask?

Anyone else that we're going to hear from from the other utilities? Thank you, Mr. Aslin.

Any of the utilities wish to return to the podium? Okay.

I think we're down to public comment, is that correct? Okay, good.

Please, anyone wish to speak? You can approach either podium. Do we have anyone on the phone? No.

I think we're just about done. There is next steps on here, and, Dr. Jaske, I'm glad you're -- oh, wait, we do have someone that's going to speak here.

MR. RUFO: Yeah, I guess I --

PRESIDING MEMBER BYRON: Mr. Rufo.

MR. RUFO: -- just in that perspective of where are we compared to 1:00. I personally think there's still a significant amount of uncertainty about the amount of energy efficiency that's in the reference forecast --

ASSOCIATE MEMBER PFANNENSTIEL: So do I.

MR. RUFO: -- and where it is and what it is and what it isn't. That really needs to be addressed. And I have some concerns, too, about the backwards attribution issues and what the implications for energy efficiency policymaking are of that.

I have a feeling we can probably figure -- it can be figured out, but right now it still looks pretty ambiguous or unclear from the point of view of what's in which pocket. And how much is in and how much is not when you get into the higher goals, levels of the energy efficiency.

Thank you.

PRESIDING MEMBER BYRON: Yes, thank you.

MR. SKALA: Hi, I'm Pete Skala. I was the lead analyst on the 2006 LTPP, and I'd just like to take a crack at answering that question of what on our fourth floor we'd prefer between a mitigated and unmitigated. We like option B, both.

Because it's important to our Commissioners to understand -- well, it's important to everybody to have the bottomline number that we're all shooting for.

We also do kind of want to understand

what effects our programs did have on coming to that. So, we do need a before and after.

It might not have to be the same before and after that the CEC comes up with. Maybe we need something that shows our different lines for our different definitions. But ultimately we're going to need to develop both, either in our proceeding or hopefully here.

PRESIDING MEMBER BYRON: Thank you. And you said you're from the Public Utilities Commission, correct?

MR. SKALA: Yes.

PRESIDING MEMBER BYRON: Good, thank you.

Well, if there's no other public comment, Dr. Jaske, I think it's perfectly appropriate, since you started us off with the overview and questions, to give us a sense of your slide in your presentation on next steps for this process still applies, perhaps.

And/or if there's something else that you've taken from this. This is my first full exposure to this complicated issue. And I'm not fully convinced we got much resolved today, either.

But there were some good ideas that came up from this that we may work with going forward. But I'd like to hear from you, please.

Without the biography. I'm not going to read the bios --

(Laughter.)

DR. JASKE: I think that we heard the utility forecasters say they want confirmation from the Energy Commission that there's a high level of overlap. They want us to say that so that it will sort of cause their anxiety level to go down.

We heard very little from the utilities about -- or the unit, the section, whatever the right terminology is at the utilities -- who are dealing with the long-term potential. The ones who are going to be asked to sort of contribute to analyses of what ARB sets out as energy efficiency goals that presumably the Energy Commission and the PUC are going to somehow or other recommend to ARB.

Tomorrow you're supposed to be dealing with a GHG decision that has got some words in there that talks about having, you know, very high efficiency programs as a mandate.

We heard from Mr. Rufo about how the existing potential studies have been organized, and the degree which they do or they don't, you know, sort of couple up to the staff's forecast.

By the way, I think I want to extend some appreciation to the PUC for, in effect, funding Mr. Rufo to come here today, since he and the IOUs are paying Mr. Rufo's meal ticket. And it should be obvious that to the extent we dive into this in detail, that more involvement with ITRON and the potential study is going to be necessary.

My basic opinion is that if you want to treat this issue seriously, all of what I said here is still applicable. We have just barely begun to come to grips with the minutia involved in this subject.

At only one point did Tom Gorin describe how the staff's forecasting models have a level of disaggregation that matches up to what Mr. Rufo talked about. And that was the point where he talked about different levels of ceiling and wall insulation, and how those changed through time.

And the other examples of talking about freezer efficiency changes over time, he really

talked about how the average freezer, in two respects, the average across a bunch of individual purchase years, but within purchase years, it was only, in effect, a single value.

So there was no distribution of refrigerator purchase efficiencies in any given year, like 1980. There was only a single one relative to some base year.

And what Mr. Rufo's model or other DSM potential models would do is say not only is there that effect of the standard, there's higher efficiency freezers that could have been purchased. And there probably were utility programs that affected that distribution function.

And there's sort of, in effect, another whole axis of accounting for that dimension of things that we're not taking into account in any overt way.

And so if you're really trying to dovetail analyses of the staff's model with at least the potential study and its emphasis on individual measures, we sort of have to just plow through something like the sequence of events.

There possibly is a different answer to this question about dealing with the short-run

next round of EE programs versus the sort of new issue that emerged, you know, as part of the AB-32 process and our scenario analyses project in the IEPR, and that is the high, high penetration scenarios that no one's really been paying serious public policy attention to. It's only been in the ITRON study as sort of backdrops to sort of the near-term focus.

So, I'm not certain how many resources it would take to do something like this. And maybe there's multiple options about the level of intensity and the schedule over which some sequence of steps like this can be taken.

But I don't think we're going to be able to really do justice to the major issues unless we sort of embark on this path. I think what I might suggest is staff work up some options; float those to you for you to in turn, then, think about how you want to involve the industry. You may want to float something out as a draft order, or some other directive and get some feedback.

And sort of go into this kind of eyes-wide-open, knowing how long it's going to take; how much resources it's going to require; and what the opportunity cost is going to be.

If we're going to put all these resources into this, what are we not going to do. Both staff, as well as other interested parties here today.

PRESIDING MEMBER BYRON: Good. That's somewhat like building the Bay Bridge, though; got to keep the traffic flowing at the same time we're building the new bridge.

DR. JASKE: That's why the last bullet's on this slide.

PRESIDING MEMBER BYRON: Right. Well, Madam Chairman, any more comments?

Astoundingly, we are absolutely on time. Thank you all for coming today, and for your input. We appreciate it very much.

We'll be adjourned.

(Whereupon, at 5:03 p.m., the workshop was adjourned.)

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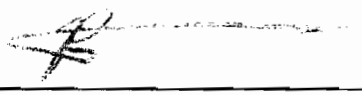
CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Committee Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 1st day of April, 2008.



PETER PETTY