STAFF WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	)
	)
Preparation of the 2008 Integrated Energy Policy Report Update and The 2009 Integrated Energy Policy Report	) Docket No. 08-IEP-1B
	)
Impacts of Higher Levels of Renewables on the Electricity System; Summary of Recent Studies	)

CALIFORNIA ENERGY COMMISSION

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Reported by:
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STAFF PRESENT

Suzanne Korosec

Michael Jaske

Pam Doughman

Donna Parrow

PANELISTS PRESENT

Jan Hamrin
Center for Resource Solutions

Dora Yen Nakafuji
Lawrence Livermore National Laboratory

Snuller Price
Energy and Environmental Economics, Inc.

Jaclyn Marks
California Public Utilities Commission

ALSO PRESENT

Mark Bolinger (via teleconference)
Lawrence Berkeley National Laboratory

Bruce Baccei
Sacramento Municipal Utility District

Jane Turnbull
League of Women Voters

Merwin Brown
California Institute for Energy and Environment
University of California

I N D E X

P R O C E E D I N G S

10:05 p.m.

MS. KOROSEC: I'm Suzanne Korosec; I'm leading the Energy Commission's Integrated Energy Policy Report effort this cycle.

A few housekeeping items just to get us started. The restrooms are out the double doors and to your left. There's a snack room on the second floor at the top of the stairs under the white awning.

And if there's an emergency and we need to evacuate the building, just follow the staff out the door to the park across the street and wait for the all-clear signal.

Today's workshop is being webcast, and for parties who are listening in on the webcast who may wish to speak, the call-in number is 888-566-5914; the passcode is IEPR; and the call leader is myself, Suzanne Korosec.

To set the context for today's workshop the Energy Commission's IEPR Committee, which consists of Commissioner Byron and Chairman Pfannenstiel, has directed the staff to evaluate what physical, operational and market changes will need to be made to California's electricity system to be able to support higher levels of renewables.

While the focus is on 33 percent renewables by 2020, the Committee also believes we need to begin looking at system needs for even higher levels, perhaps even 50 percent by 2050.

Expanding the state's renewable portfolio standard to 33 percent by 2020 is a key element in the Air Resources Board's preliminary recommendations for reducing our greenhouse gas emissions. And the Committee believes that renewables are also essential to meeting our 2050 greenhouse gas reduction goals.

And that both policymakers and stakeholders need to fully understand the impacts of moving to these higher levels of renewables.

Today's workshop is the first of three staff workshops on this topic. To begin this evaluation, today we'll be identifying what analyses have already been done; what analysis remains to be done; and what key variables the Energy Commission needs to focus on in doing our analyses.

These three workshops and the analyses are an interdivisional effort here at the Commission with involvement from our siting, efficiency, renewables, electricity analysis and research and development divisions.

In addition, we'll also be coordinating very closely with the Public Utilities Commission and the California Independent System Operator, as well as other stakeholders. But because this is a statewide issue, and will affect more than the investor-owned utilities and the Cal-ISO control area, we'll also be working closely with the publicly owned utilities.

Our intent really is to minimize duplication of effort to the extent possible; and to make it easy for stakeholders who may have to participate in multiple processes.

We're beginning this discussion now as part of the 2008 IEPR update. But because of the short timeframe for the 08 report, which will be out in November, the bulk of the analysis will really be done in the 2009 report. What we're doing now is just identifying what it is we need to do, and getting stakeholder buyoff on whether we're on the right track on how we're going to be doing our analysis.

This is a very complex issue. It will have significant statewide impacts on grid operation. So the Committee believes we really need to have a robust analysis on which to base our conclusions and our recommendations.

We're really looking to you, the stakeholders, to help us understand what variables we should be focusing on. Obviously, transmission has been, and continues to be, the primary barrier to renewables development in the state.

However, grid reliability is also a major consideration. And we need to understand the operational impacts of integrating large amounts of renewables.

The Committee believe we really need to fundamentally change the way we operate our grid to be able to incorporate these levels of renewables.

We've made these kinds of changes in the past, for example, in the late 70s and early 80s when we were integrating large numbers of independent power producers in response to PURPA requirements.

We can also learn from experiences in Europe where many countries there have significantly increased their levels of renewables while maintaining grid reliability. And we need to understand whether and how their strategies can be applied to California.

On the supply side we need to make some broad assumptions about the potential resource mix, both renewables and conventional. And that will have a big impact on where our analysis goes.

For renewables, we need to figure out what the resource mix could be, and also take into account technology changes and improvements that will be taking place over time.

In the past few years we've seen a lot of wind resources bidding into utility solicitations. But then more recently now we're seeing huge amounts of solar coming in. And I don't think ten years ago anybody would have expected 40,000 megawatts of solar projects being proposed in the state. And we need to think about what other changes we may see over the next ten years that we may not be envisioning right now.

With the variable nature of these resources, we're going to need some kind of backup to maintain grid stability and reliability. And we need to understand what that backup is going to be, whether it's natural gas peaking plants, or energy storage, or demand response measures, or some sort of use of smart grid technologies. Or is most likely some combination of those.

We also need to think about the potential environmental impacts of siting these large power plants, and what effect those impacts will have on the ability of the plants to be permitted and built.

For conventional resources we'll need to make assumptions about where the existing fleet will be in 2020. What plants may have retired. And what replacement power for those plants will be and where it will be located.

We also need to consider policy efforts to reduce the impacts of once-through cooling at existing and new power plants, and what effect that will have on the existing power mix.

We'll need to think about retirement and repowering of aging power plants, and also what may happen when the nuclear plants come up for relicensing after 2020. We'll also need to make assumptions about expected imports, both conventional and renewable.

On the demand side, we'll need to make some assumptions about the amount of energy efficiency we expect to see in 2020, and how that will effect electricity demand.

We will also need to consider the effect of demand of the electrification of the transportation system, both with increased electric vehicles and of the state's port facilities.

We need to consider how much demand response technologies and strategies can contribute to offsetting the effects of large amounts of variable renewables.

There are emerging technologies that can improve grid stability, or provide backup in the form of energy storage. But we need to understand what those technologies are in terms of development and commercialization. And what the costs will be, and how much they'll realistically be able to contribute by 2020.

On the cost side, we need to understand the potential costs of integrating large amounts of renewables, with the primary question being costs compared to what. With natural gas prices continuing to increase and continuing to be extremely volatile, renewable generation may become more competitive in the future.

We need to understand the impacts of

renewables in reducing natural gas demand and price. And also recognize the value of renewables in providing a hedge against natural gas volatility.

We also need to consider the costs of climate change when evaluating the costs of integrating renewables, as well as the potential costs that will be associated with meeting the state's greenhouse gas reduction goals.

So, that's a very quick and dirty view of the things we'll be looking at. And we do recognize it's a very complex issue, and that's why we need your input of where we should be focusing our analytic efforts and coming up with a set of reasonable assumptions to use in evaluating this issue.

And with that I'll turn it over to Pam Doughman to begin today's discussion.

Thank you.

MS. DOUGHMAN: Thank you, Suzanne. The agenda for today is in two parts. We have seven topics that we will be discussing. And we will discuss the first four topics in the morning; then break for lunch; and then have topics 5 through 7.

So, I'm going to give a brief overview

of topics 1 through 4. Then we will have a panel discussion and public comment on those topics.

Then we'll do, after lunch, we'll have a series of presentations from authors of previous studies on the topic of achieving 33 percent renewables. And then I will finish up with an overview of topic 6 and 7. Then we'll have a panel discussion on topics 5 through 7 and public comment.

So, we're kind of going through the presentation panel discussion loop twice. That's the plan for today.

So, topics 1 through 4. First, what are we talking about, 33 percent of what. I'm just going to walk through what that means. Estimating 33 percent of statewide retail sales for 2020.

Then I will compare resource mix scenarios that have been used in recent studies on achieving 33 percent.

Then briefly I will talk about the impacts of contract delays or cancellations on meeting existing renewable portfolio standard goals.

And then number 4, I will talk about the range of potential wholesale and retail price impacts and strategies to mitigate negative impacts. I'll talk about the range of assumptions and levelized costs in the recent studies on achieving 33 percent renewables.

But before I go any further I want to thank everyone for coming today. And I see we have a full house. And I look forward to your comments.

So, then the topics for the afternoon. Topic number 5 is to go over operational and physical changes needed to integrate renewables while maintaining reliability, including discussion of when those changes would be needed and at what level of renewable penetration.

And in that discussion our invited speakers will discuss the impacts of using peaker plants; the potential and the need for energy storage technologies to help maintain grid reliability.

Then I have a presentation prepared by Mark Bolinger and Ryan Wiser regarding potential impacts on natural gas demand, supply and price. Mark Bolinger will be available to answer questions on the phone, but I'll be walking through the slides with you here.

And then I'll provide a brief overview of the environmental concerns and studies that discuss mitigation for developing large-scale renewable facilities.

As Suzanne mentioned, this is the first of three workshops. The second workshop will be on July 23rd. And that workshop will discuss transmission issues for 33 percent renewable energy by 2020, including a discussion of the RETI initiative and related activities.

On July 31 the Public Interest Energy Research group here at the Energy Commission will discuss research and development needs and enabling technologies for integration of high levels of renewable energy into the electricity system.

And then August 21, we will have an IEPR Committee workshop. And that workshop will integrate and discuss the public comments, the findings, the presentations that have been presented here at these three staff workshops.

Okay, on to the first topic. Estimating 33 percent of statewide retail sales for 2020. Now, the different studies have approached this according to the purpose, if they're focusing on how the investor-owned utilities can meet 33 percent, then the estimate is what does it mean in the IOU context.

But the goal is intended to be statewide, and so in combination we need to have a series of studies that are looking at different particular groups, publicly owned utilities, IOUs, different impacts in different regions of the state. And we need to see how it all fits together statewide.

So, I have an excerpt here from the California Public Resources Code that just points out that it is the intent of the Legislature, in establishing the renewable portfolio standard, to increase the amount of electricity generated from eligible renewable energy resources per year so that it equals at least 20 percent of total retail sales of electricity in California. So it's 20 percent by 2010.

And, of course, the law has very specific set of requirements for investor-owned utilities, retail sellers, and then requires publicly owned utilities to develop similar renewable energy programs.

And then in the Governor's response to

the 2003 IEPR and the 2004 IEPR update, he wrote: Beyond 2010 the goal of achieving 33 percent of our energy from renewable resources by 2020 is possible, but we must work together to determine the most effective means of attaining this goal.

All energy suppliers, including municipal utilities energy service providers and community choice aggregators should meet the same renewable energy goals required of investor-owned utilities.

So, in that context we're looking at a statewide estimate of 33 percent of retail sales of electricity by 2020.

So, in making that calculation we based our estimate on this source here, California Energy Demand 2008 through 2018. And I have the link here.

So, the estimate for statewide retail sales in 2020 is just over 308,000 gigawatt hours delivered to end users. So a third of that is about 102,000 gigawatt hours statewide. This excludes non RPS deliveries from CDWR, WAPA and MWD.

Energy efficiency and distributed generation beyond the amount included in the forecast would reduce retail sales and reduce the renewable energy required for 33 percent of retail sales by 2020. Estimates of generation to meet this requirement must take transmission lines into account.

Okay, now this slide compares the resource mix scenarios by technology. And so we have on the bottom, solar; the different levels of solar that are included in the resource scenarios in the study completed by the Center for Resource Solutions for the CPUC in 2005. Now, that study was for investor-owned utilities only. And it assumed 20 percent by 2010 was already achieved.

Then we had in 2007 the Energy Commission published the Intermittency Analysis Project. And the scenario there was looking at the role, how the statewide grid would need to adjust to a high level of penetration.

So when they were compiling their scenario they were adding resources while maintaining grid reliability in their modeling process. And so where they could add additional intermittent resources, that was the preference.

And then also in 2007 the Energy Commission prepared a scenarios analysis project.

And we have the scenario that they used on this chart, as well.

And then this year, E3 has prepared a greenhouse gas model. And in that model they have included a high renewables, high efficiency scenario. And this is the resource mix for renewables that's included in that scenario. That model is designed to allow the user to input their own scenarios. But this is the particular model that they have presented so far.

So this is the same, but this is in terms of energy. The previous slide showed the resource mix in terms of megawatts. And something I want to call to your attention is there is a goal to have 20 percent of the state's RPS met through biomass and biogas. And so one area for additional research is to look at really modeling how to achieve that, and how that might affect some of the results of previous scenarios.

And this just summarizes some of the renewable energy goals in the state, putting the concepts in terms of energy. So, we see that in 2010 achieving 20 percent renewable energy, 20 percent of retail sales is about 55,000 gigawatt hours. Increasing that to 33 percent by 2020 requires a total of 102,000 gigawatt hours.

We also have the California Solar Initiative which is for 3000 megawatts of new solar. And that would mean about 4000 gigawatt hours.

Then we have the state bioenergy goal from executive order S0606. And that is for 20 percent of the RPS from biopower, which is equivalent to about 11,000 gigawatt hours in 2010. And then 20 percent of the 33 percent goal would be about 20,000 gigawatt hours from biopower.

Then also, as Suzanne Korosec mentioned earlier, renewable energy and 33 percent by 2020 is an important part of efforts to reduce greenhouse gas emissions. And so this slide shows how the different goals renewable energy, what they mean in terms of gigawatt hours.

Okay. So part of our purpose today is to summarize what we know so far and then to think about additional scenarios and additional analysis that we need to fully understand and anticipate the changes that will be needed in the electricity system to accommodate 33 percent renewables by 2020.

So, there are a number of uncertainties

that we need to take into account. And Suzanne Korosec introduced many of these. For example, once-through cooling, greenhouse gas emission policies, fuel and development costs and to really understand the impacts that these different uncertainties may have. A rigorous study of the electricity system needs to include examination of a range of different renewable and conventional generation mixes to insure system stability at the least cost possible, remembering to compare the costs to the costs of the impacts of climate change.

So, keeping in mind compared to what. You know, what will natural gas prices look like in 2020, and what are some of the uncertainties surrounding those issues.

Okay, so keeping in mind that this is a statewide goal, I have a brief comparison here of publicly owned utilities and investor-owned utilities, renewable energy contracts and projects.

And the existing resource mix varies by utility, and varies quite widely among publicly owned utilities. Some of the publicly owned utilities already have very high levels of renewable energy, and others still have a fairly greenhouse gas intense resource mix.

And many of the publicly owned utilities have already established very impressive targets for renewable energy, including 33 percent by 2020. And even, I think, beyond that target in some cases.

Here I have some excerpts from the 2007 Integrated Energy Policy Report just pointing out that the publicly owned utilities have been procuring increasing levels of renewable energy and I have some of the numbers here.

As a note, new publicly owned utility wind projects make up almost all of their new capacity with the two largest projects located outside of California.

As of July 2007 more than 550 megawatts of the contracted new capacity was online and delivering energy to the California publicly owned utilities, while only 324 megawatts of new repowered or restarted RPS capacity contracted by the investor-owned utilities were online as of early August.

This slide compares the contract status of the different investor-owned utilities, the large three investor-owned utilities in California for new, repowered or restarted capacity from contracts signed since 2002 by the minimum levels of megawatts in those contracts.

And the green at the top of each bar shows the percentage of contracts that are online or on track but not online. And you can see the large majority, in all but the case of San Diego Gas and Electric, are on track but not online.

And then we have, in white, at the lower end of each bar the amount of megawatts, or the proportion of contracts that are delayed. And most of those are delayed and not online.

And this slide breaks out the same information by technology. So we see that much of the delay is in wind projects and also solar thermal.

This slide is from the CPUC, their report to the Legislature from April 2008 regarding renewable portfolio standard progress in achieving the renewable portfolio standard for the investor-owned utilities.

And they have analyzed the contracts, and they have, in this graph they show the target of 20 percent of expected IOU retail sales at about 34,800 gigawatt hours. And they show the contracts in different levels of risk. And so they show low risk, medium risk, high risk and 2007 short list not yet rated.

So this, I think, shows where we are and what we have in the pipeline, and the risk associated with the contracts that are in the pipeline for the investor-owned utilities.

The CPUC also analyzed the risk factors for 2010 RPS generation. And the PTC, the availability of the production tax credit is the number one risk factor in terms of the percent of 2010 generation that's affected by this factor.

Transmission is the second. Other factors include developer risk factors, financing, site control, permitting, a price reopener, military radar, technology, fuel supply and equipment procurement.

This slide compares levelized costs that have been reported in the different analyses conducted so far. These are cost of generation in terms of 2008 dollars for renewables needed to achieve 33 percent by 2020.

And so we can see in the fine print at the bottom we've listed the studies included in this comparison. And some of these studies included a broader range of technologies than other of the studies.

And so for biomass, IGCC, for example, there were only a few studies that included an estimate for that cost. So the narrowness of the range reflects the number of studies, rather than the certainty regarding the price. But this gives a general ballpark perspective on what are the costs that the studies have published -- the studies have found so far. For wind, landfill gas, geothermal, solar parabolic trough, biomass stoker, biomass IGCC and anaerobic digestion.

Now, it's very important to keep in mind that when you're estimating levelized costs you need to have a number of input assumptions. And this slide shows the effect that different input assumptions can have on your calculation of the levelized costs. And I've tried to put these all to scale so you can see capacity factor is one of the largest or the input assumption that has the largest effect on the resulting estimate of levelized costs.

And so the studies vary in their input assumptions, and that affects their estimate of the levelized costs of generation.

Here is a set of supply curves prepared by E3 for 20 percent and 33 percent RPS. The bottom set of curves shows the net cost, which is the total cost less displaced energy and capacity. And then the top set of curves shows the total cost, including buss bar transmission and integration costs.

So, it looks like geothermal, wind are the lower costs for achieving 20 percent by 2010. For achieving additional renewables to achieve the 33 percent by 2020 target, biogas is estimated to have the lowest cost, followed by wind, geothermal and solar thermal. And biomass has a relatively high total cost in the E3 supply curve shown here.

Regarding potential retail price impacts, the report prepared by the Center for Resource Studies for the CPUC in 2005 had the results shown here. And they're showing that over the long run renewable energy have a beneficial net impact on costs to ratepayers, costs to California ratepayers.

And here we have potential retail price impacts from the E3 study. And they show that the total investment costs increased from about $24 billion to about 60, when we're moving from 20 percent RPS to 33 percent RPS. They show the change in rates and costs between 2008 and 2020 in real terms, the change in rates for 20 percent RPS they show at 13 percent, and the change in rates for 33 percent RPS they show at 17 percent.

Okay, and that concludes my introductory presentation, which was intended to give the people attending today's workshop an overview of what the studies have found so far in looking at achieving 33 percent regarding the first four topics for today's workshop.

So, now we're going to have a brief discussion of the findings in the scenario analysis project for the first four topics. And before we do that, let me briefly introduce the panel.

We have -- I'm very happy that everyone was able to participate. We have quite an expert group here. Dr. Michael Jaske is a Senior Policy Analyst in the electricity supply analysis division of the California Energy Commission. For 20 years he was the Chief Demand Forecaster giving technical direction for the Commission Staff's independent demand forecast.

Dr. Jaske plays an active role in the development and advocacy of the Energy Commission's positions on retail market structure, resource adequacy and other planning processes.

Dr. Jaske has been involved in numerous collaborative efforts between the Energy Commission and the CPUC. And he has testified numerous times before the Energy Commission, the CPUC and other California agencies.

He is also a participant in the WECC loads and resource subcommittee, developing a resource adequacy methodology for the WECC. Along with his work as a member of the IEEE Power Engineering Society, he serves -- in that group he serves on the energy policy committee of the IEEE USA to educate national policymakers on electricity issues.

The second member of our panel is Dr. Jan Hamrin. And today she is representing CRS, the Center for Resource Solutions. Dr. Hamrin is CEO of HMW International, a consulting firm specializing in implementation of sustainability energy policies. She is the past president of the Center for Resource Solutions, a nonprofit organization created to foster leadership in the implementation of clean energy and sustainable development practices through education, training and expert assistance.

Jan's work has provided policy and technical support for the implementation of renewable energy and energy efficiency programs throughout North America and globally.

Internationally, Jan was a key expert in the development of a renewable energy law in China. She has also worked on renewables, energy efficiency, and climate policy in Mexico, Brazil, Europe and elsewhere.

She has co-authored numerous publications and serves on Advisory Committee for the International Energy Agency, the Commission for Environmental Cooperation, the U.S. Department of Energy and others.

The next member of our panel is Dr. Dora Yen Nakafuji. She is a Staff Researcher at Lawrence Livermore National Laboratory, working in the National Security Engineering Division and leads the National Transmission and Energy Resilience Response Analysis Effort, which helps evaluate the risk and vulnerabilities related to the evolving power grid.

Her area of focus include renewable energy and technology, transportation and operational system analysis. And she served at the Technical Lead for the Public Interest Energy Research Wind Energy Program, and Renewable Integration Initiative at the California Energy Commission.

Prior to that she worked as a technical consultant in the high-tech electronics and aerospace industries.

Then our next panelist is David Hawkins. He is Principal Engineer working in Operations. He is a principal investigator for the integration of renewable resources at the Cal-ISO. The Cal-ISO has a major project to assess the operational impact on intermittent resources such as wind generation. The objective is to identify potential grid operations, market operations and transmission issues and develop strategies to mitigate these issues.

He is also responsible for assessment of new technologies such as storage technology and their potential application for solving operating issues.

He has served on many professional and

industrial committees and is current the Past Chair of the WECC Performance Work Group, and Chair of the Wide Area Measurement Task Force.

And then we have Snuller Price. Snuller Price is a partner with Energy and Environmental Economics, Incorporated. He leads the E3 consulting team on GHG modeling for the joint CPUC/Energy Commission GHG docket. He has 15 years of experience supporting utility, state and federal government clients with resource planning, including integration of distributed resources, energy efficiency, distributed generation and demand response into resource planning.

He supports the market price referent proceeding at the CPUC and has supported the Energy Commission renewable program in the past.

And then our last panelist is Jaclyn Marks. Jaclyn Marks is in the Energy Division at the CPUC. She is a member of the renewable portfolio standard team. She is a policy analyst, and works on policy design and implementation of the RPS.

Her projects include analysis of a 33 percent RPS energy technology innovation and review of RPS power purchase agreements.

Jaclyn holds a masters degree in public policy from the Harvard Kennedy School. And earned her under-graduate degree from the University of Wisconsin at Madison.

So, I took the time to go through the bios. I know that's kind of unusual, but we have -- I just wanted you to understand the background, the expertise of the panelists here. And certainly we look forward -- I know we have many experts in the audience here, and so we look forward to a stimulating exchange of dialogue.

And what we're planning to do is first have a presentation by Dr. Jaske. And then we'll switch to a conversational format with the panelists discussing the questions in the notice for the workshop on topics 1 through 4. Then we'll have public comment regarding those topics.

(Pause.)

DR. JASKE: Good morning, everyone. For the record my name is Mike Jaske. And what I'm going to do here this morning is give an overview of the scenario analyses project that was undertaken as part of the 2007 IEPR during the course of 2007.

There were four workshops that were

conducted as part of the 2007 IEPR, either wholly or partly addressing this particular project. And it ended up being showcased quite a bit in the IEPR, itself, as a way of examining high energy efficiency, high renewable approach to greenhouse gas reduction.

So to understand this study to have been a what-if project. We were not attempting to declare that high efficiency or high renewables, which will be the focus today, of course, would happen on the schedule. And to the extent that was assumed in the various scenarios, they were thought to be feasible; they were thought to be roughly cost effective.

So, given those presumptions we developed scenarios; and our main emphasis was really on this first sub-bullet of trying to understand the CO2 consequences of pursuing these preferred resource strategies in large volumes.

And this study was also done on a WECC-wide basis. There were specific scenarios for California along, or for all of the west. And one of the objectives of doing that analysis was to better understand how imports would change through these quite high penetrations of efficiency and renewables.

So, very quickly, you know, we identified the broad themes of our scenarios; set about to develop the detailed assumptions that would be necessary for production costs sort of project, because that was our tool for developing results.

We started with a basecase that, in fact, was what was in the Global Energy, now Vintex, fall 2006 reference case; tweaked that a little bit to make it conform to some Commission Staff preferred assumptions.

And then as we developed the various preferred resources or scenarios we were sort of generally backing out the generic editions of that initial case, adding in the detailed assumptions of a particular case; verifying that the dataset satisfied resource adequacy protocol, which I'll talk more about this afternoon; prepared the dataset; run it; review it.

And then we did some limited analysis or sensitivity to fuel prices and hydro. And those -- all of these results are documented in detail still in the form of the preliminary staff documentation. The final documentation we had expected to publish by now, but it is imminent within a few weeks and will be up on the website.

So just to remind you, the three broad preferred resource categories and the sources of those assumptions. For energy efficiency, those are shown for extensive penetration of rooftop solar PV in concert with the objectives of the California Solar Initiative. There have been a number of studies done for that through PIER primarily. There were also some studies that Navigant did for the Arizona Department of Commerce, and we made use of those.

And then in the supply side portion of renewables, of course, there's the IEP project. And we drew upon that to a considerable extent, as the framework for our assumptions. And then also on a westwide basis for the Clean and Diversified Energy Analysis Consortium that worked pursuant to the Western Governors Association objective to create an analysis to show a high renewables case.

So we drew upon, for focus on renewables here today, on the IEP and the CDEAC studies for many of our underlying renewable generating assumptions.

We were focusing on renewables and

pursuing high penetrations of them. We were not investigating the details of RPS requirements. And so all of the minutiae of what RPS means, you know, what amount of load, you calculate it relative to do you even worry about whether you're satisfying exactly 33 percent of something. Those were not things that we were particularly focused on.

We, of course, recognize that transmission development is necessary for virtually all of these resources. Everyone's now aware of that. We attempted to do some degree of transmission analysis. We, I would say, made an approximation of that at the workshops. A number of the shortcomings we were reminded of, and we acknowledged those limitations. And other studies are attempting to move on and beyond.

Clearly there are many operational and reliability issues associated with some forms of renewables, some technologies. Those were addressed, to some degree, in this study. And I'll get into the resource adequacy aspect of that this afternoon.

Clearly an issue is the detail of what it means for intermittent generation to be at high levels and how various forms of backup resource are necessary in order to address the variability of such intermittent resources.

We did not study in the scenarios project the cycle-by-cycle, minute-by-minute, hour-by-hour variation. Rather, we focused at the planning level how these things performed differentially across the seasons of the year, the months of the year and dealt with that through our resource adequacy protocol.

And similarly, we applied that same kind of concept in our analysis of high renewables in the rest of WECC, but our primary assumption again came from the CDEAC results not any independent analysis of renewables out there in the rest of the west.

So, a thing to keep in mind about the study is that we encountered many uncertainties, some of them were anticipated, some were not. There's a whole range of things that were excluded simply by the focus of the design of the study.

For example, we were conducting a physical study; we were not examining the requirements for individual LSEs and all of the contractual issues associated with LSEs satisfying

RPS. Rather we were doing a physical study of renewables or energy efficiency or both of them, and looking more at the broad system consequences as opposed to LSEs.

So that means that our results are -- the design of the study, itself, precludes certain conclusions about individual LSE ramifications.

It was thought at the time that this would be a starting point for some more useful studies that the staff might undertake in the next cycle. And, in fact, that happened more quickly in the form of the GHG study that E3 undertook as part of the PUC. Sort of loosely started from the same kinds of high renewable, high efficiency assumptions that we had, and moved on from there to examine more LSE-specific details.

We found that there was a major change in the portion of imports that are short-term market purchase, not linked to the individual remote resources that are owned by LSEs. And indicated that a necessary followup with more detailed examination of this whole issue. And I'm not sure that that has yet been undertaken by any subsequent study.

And additionally, we found a lot of

variation in predicted CO_2 emissions from hydroelectric production variation. And that's an element that needs to be taken into account in the design of the electricity sector's requirements; can satisfy AB-32 goals. And that's the kind of detail, I think, has yet to be surfaced in the ARB process.

So, here is the source of the preliminary documentation. As I said, the final report will be posted very soon.

Now, let me turn, after that brief introduction to the overall study, to how it addresses the specific questions in our agenda and the notice for today's workshop.

So in the broad area of questions 2a, b and c, let me just indicate how it is we constructed our scenario. So in the end there were 13 of them. We actually started off doing nine, but in response to questions from Commissioners, we ended up doing two more energy efficiency scenarios and then two more composite scenarios that had both efficiency and the case 4a level.

So, these numbers, as they increase, indicate generally the threes are the energy efficiency, the fours are renewables, the fives are combinations. The a means California, the b means westwide. The d and e's are what were added in response to the Commissioner requests. So they were the last ones done.

This chart will indicate the magnitude of the energy efficiency and the renewables assumptions. So, as you're reading this chart with energy efficiency on the horizontal axis and renewables on the vertical axis, you can see sort of in the middle of the chart is the case 1b. That's the case that would imply moving forward with the kind of requirements that were going to be placed on utilities through existing RPS statute or existing energy efficiency program authorizations.

And then you can see for the efficiency side, moving from case 1b over further and further to the right there are increased levels of energy efficiency savings.

And then in the case of renewables, going back to case 1b in the center, rising vertically that's the incremental renewables assumption in case 4a. And then from that point going further to the right you see the case 5a, d and e.

So, here is a fundamental difference between this analysis and RPS. As Pam went through earlier, the focus is on retail sales. This analysis of the composite effect of renewables and efficiency does not take into account the retail sales angle. So there's no diminution of the amount of renewables as energy efficiency increases.

We simply assumed that they would be additive. And from the perspective of this study that was done in order to maximize the backout of conventional resources, and therefore maximize the GHG reduction.

Of course, in a formulae approach like the current RPS, this would not be the predicted consequence. There'd be some different pattern.

We didn't actually, at the time, calculate what the sort of RPS equivalence of our scenarios would actually be. We simply reported it on gross total sales. Here's total renewables. Subsequently we have examined what our sort of RPS equivalent would be, and in the case 1b we had about 17 percent on a net retail sales basis. Case 4a, which is the renewables increment over and above the same energy efficiency assumption of case 1b gets us to 32.6 percent, just short of 33 percent.

And then case 5a, which is the introduction of further energy efficiency brings us to about 34 percent on an RPS equivalent basis.

So, sort of by happenstance the level of renewables that we assumed gets us into the right zone of a 33 percent formulation.

One of the things that I want to remind you of is that as we did our analysis of one of our principal objectives in the scenario study was trying to understand what resources would be displaced, both in terms of new construction avoided or existing resources let run less hard.

So, this stack bar chart is a very compact way of trying to show the energy consequences in 2020 of all 13 scenarios, starting at the left with case 1 and ending up at case 5e to the far right.

Various colors of the legend are trying to be consistent across the different scenarios. I think we got that part right. Some of them are so small you're not going to be able to read. But generally the flashier colors, which I think in your copies, unfortunately, are all shades of gray, are the preferred resources, either renewables, energy efficiency or rooftop solar.

And sort of right in the very center the green cross-hatched part is natural gas. And clearly, as expected, as one adds renewables in California or elsewise, you're going to have a reduction in generation from conventional resources. In California, those are almost all gas-fired. There's very little oil and a couple petroleum coke facilities.

So if we were to focus in particular on the second bar from the left, case 1b, just sort of focus on that. And the amount of natural gas there, that slash part, then move about two-thirds of the way across with the case 4a, which is the renewables case.

So all of the preferred resources have increased in their particular elements. And the natural gas has gone down, but not quite as much as the renewables have gone up. Well, why is that? Look at the very top element between those two bars. Case 1b has quite a bit of market purchase imports, short-run economy purchase, economy energy kinds of resource. That's much smaller in the case 4a.

So, part of what has happened is that that portion of imports has been displaced by instate California renewables.

And there are similar, many more details and actual scenario documentation, itself, that just this bar chart for those people who are interested in examining in more detail this whole issue of instate development affecting imports.

So, let me now turn to the questions having to do with cost, 4a and 4b in particular. When we were doing the cost analysis and the scenario project we were attempting to cover all the capital costs of new resources added in any of the scenarios.

And so for example, in case one, which was the reference case developed largely by Global Energy's fall 2006 reference case, there's a lot of generic resources added and very little preferred.

By time we're backing those out and adding preferred resources. We're costing those preferred resources and their capital costs, attributes, and we're able to see the capital cost difference between the preferred resource scenarios and, you know, the more business-as-usual ones dominated by conventional resources.

We're also, of course, using a production cost model, getting all the production costs differentials as best the production cost model can. Capital costs differentials, I should say also we're attempting to examine the transmission consequences, but as acknowledged in the 2007 IEPR cycle, we were really mostly able to get the transmission differences between the so-called bubbles in production cost model, and only incidentally able to capture the more localized transmission additions within a bubble.

So, our transmission additions are undoubtedly on the low side, and therefore transmission costs on the low side.

There's a lot of uncertainties about costs. And the cost of generation that we were using for most technologies came from the staff's spring 2006 draft cost generation report. Laid out in considerable detail what they assumed. But, as one tracking this industry really knows, in that period of time, 15 months, cost numbers were already up significantly, maybe 10, 15, 20 percent. Tremendous competition in particular for some kinds of renewable technologies like wind turbines right now. And so it's very difficult to know where, through time, these technology costs are going to stabilize.

There's a lot of uncertainty in particular about production costs that is affecting any kind of overall cost assessment.

There's also an issue of as we're adding resources over the time horizon of analysis, which was only out to 2020, you're, of course, adding a resource maybe in 2018, 2019, or even the last year 2020. And it's going to last a long time. Levelization helps to give some treatment to that, but it's only imperfect way of dealing with long-lived resources that go beyond the time horizon of the detailed study.

So, with all those caveats, this is the result that we obtained. And I'm going to again focus on the case 1b, sort of the conventional policy continuation as of that point in case 4a.

So the case 1b, what we're showing is separate bars for California, rest of WECC and all of WECC in each of the cases. And basically, if you focus on the red, sub-bar in the case 1b group, it's about $44 a megawatt hour is the levelized system cost in 2006 dollars.

In the case 4a we're up to about $48. So this shows about a 10 percent increase in levelized costs as a result of the high renewable scenario.

As I indicated in my overview we did do some sensitivity studies. Some of them were only done for the year 2020, and so I can't convert them into the levelized format of the previous slide, or even chart. But this particular chart is intended to show the high-load hydro, the high-load natural gas price, and then a very extreme natural gas price that we did just in the year 2020.

And in the sort of middle group of columns here you can see quite a bit of variation in system cost. And as one moves from various clusters of rows at the case 1b group down to the case 4a group, you can see that the range encompassed by those cells differs significantly. So that's the thing to focus on here in this slide, is how would a high renewables case lead to changes in cost sensitivity through time.

So, that concludes what I have to say as an introduction to the staff scenario project.

MS. DOUGHMAN: Okay, thank you, Dr. Jaske. So now what I'd like to do is shift to the panel. And I'd like to have each panelist provide a brief discussion of your thoughts on questions 1 through 4. You don't need to discuss all the questions, but you can highlight the ones that are of particular relevance and interest to you.

And then I'd like to have the panelists ask each other any questions that you may have. And then we'll open it up for public comment. And then we'll break for lunch.

Okay, Dr. Hamrin.

DR. HAMRIN: Okay, I'll try to go rapidly through this. On question 1, estimating the 33 percent retail sales, we basically looked at the current load of the three investor-owned utilities, and then escalated that at 2 percent growth rate per year.

We thought this got us pretty close to a reasonable estimate for the purposes that we were doing.

I think, going forward, it might be useful to do a sensitivity analysis looking at the potential of adding plug-in hybrid vehicles, especially under greenhouse gas constrained scenario; and what that would do to the demand forecast. And what that incremental change might be.

With regard to the comparisons of the resource mix, our report had 50 percent wind. And this, remember, is going from a 20 percent to a 33 percent -- oh, I'm sorry -- going from a 20 percent to a 33 percent.

We had 50 percent wind, 20 percent geothermal, 10 to 15 percent biomass and 10 percent solar, concentrated solar.

We probably underestimated the concentrating solar and the popularity of that technology right now with the investor-owned utilities. We did not include photovoltaics in the mix. Not because we didn't think that they were important, but we didn't include them because there was a lot of policy uncertainties at the time we did the study in 2005 that would affect their availability in the marketplace. So we felt that that was just a bonus of resources that could be, and most likely would be, added in, but we did not have them as part of our resource mix.

We basically looked at what were the most cost effective resources, and what was the availability and just a lot of eyeballing onto that.

And, again, for PV particularly, I think if companies come up with a good business model for aggregating noncommercial residential PV, that that could make a huge difference. Especially the model would need to provide data inputs that meet WREGIS standards so that we would have some verification of output. But I think that that is definitely a possibility, and is an important area to look at.

So, I think that's -- many of our recommendations have to do with transmission planning. And, of course, there's a workshop on that on Wednesday. But we did look at the transmission system upgrades that were being proposed, and the availability of the resources, given those transmission constraints or expansions. So we did take transmission planning into consideration.

Fortunately, some of the things you'll see in the report if you look at it again, a lot of time was spent on transmission. fortunately a lot of those things have actually come to pass. There's been good momentum moving forward, but unfortunately not transmission lines yet.

I think if you implemented, I guess it's currently called LTTP planning, that incorporates RPS as well as a loading order and other policy aspects that you would come out with a pretty good resource plan and mix of resources.

If you're going to include out-of-state renewables, given the movement toward again climate change, greenhouse gas reduction policies in other western states, you want to make sure that whatever the rules are in the states in which those resources are located, that you're getting the carbon benefits along with the renewables.

So if a great part of the purpose is to go to higher levels of renewables in order to have carbon reduction you want to be sure that policywise those aren't being double-counted or haven't been given to some other entity.

Question 3b, current procurement process, will it produce 33 percent by 2020? Probably no way. I left a word out in the middle of that.

(Laughter.)

DR. HAMRIN: I think we need to do a lot of reconsideration of how the RPS is handled. We need to streamline it. It needs to be simpler.

There was some comment in the early comments Pam made. She was talking about the 1970s and 80s, primarily 1980s when we had a large influx of renewables and cogeneration under PURPA. That was essentially a feed-in tariff. And Europe has had great success with feed-in tariff, as well.

Obviously the difference is you know what price you're going to pay. You don't know what quantity you're going to get. With an RPS you know what quantity you're supposed to get, but you don't know what price it's going to cost. There's certainly possibilities that combine the two. From the point of view of investors in the marketplace, they like to know what price they're going to get.

We have a system right now for the RPS that is so complicated, so time consuming and so expensive for most project developers that it is very very difficult and slow to move forward. It's difficult for the utilities, it's difficult for the PUC, it's difficult for project developers. There has to be an easier way of doing this. And I suggest that you might look into some kind of combination of a feed-in tariff and an RPS target.

In that original SO4 we got over 10,000 megawatts of new renewables and cogeneration in ten years, which was not bad at the time. The companies were just getting started. The technologies were just getting started. And, of course, we had 20,000 megawatts signed up for contracts that didn't materialize.

One of the things that we did was set up a method for handling the transmission queue that required certain milestones to be completed by certain time periods. So starting with financing and permitting and moving on through to the date of which the start of construction of the project, and the date by which the project came online.

That's difficult right now because -- well, it's possible for the things over which generator developers have control. We have a number of issues right now over which the generators developers don't have control, and that are holding up a lot of the queue.

But I think that, again, a combination of things that uses some type of milestones for moving everybody forward with some significant penalties, financial or otherwise, for not meeting those milestones would be useful.

It's just we have to reduce the risk and uncertainty to everyone, but developers particularly. And the current system is just too expensive and too bureaucratic, I think, to get us to the 33 percent. So we need to streamline that.

I think that'll take care of my comments.

MS. DOUGHMAN: Dora.

DR. NAKAFUJI: Well, it's certainly a fact that moving towards a 33 percent 2020 target or any other future targets, there's definitely a lot of uncertainties based on what's presented and studies that have been done.

But I think what has to happen is that it must include a portfolio-based approach. Because whether it's wind, solar or any other renewables, it's certainly not going to be the only source of generation. I think, given our current market and infrastructure, we need to consider what the existing framework is. Work within that framework to expand and develop.

So this portfolio approach is really kind of the focus when the intermittency analysis project was initiated. We wanted to look at current transmission planning operations -- current transmission planning processes, as well as operational constraints. That also considered regulatory environments.

So, looking out for 33 percent we really tried to introduce this consistent framework, not only using cost as a driver, but looking at the transmission reliability.

So, incorporating those two metrics, or other metrics, but at the time we considered both the cost and the current infrastructure as kind of the framework or the envelope in which we could possibly move forward.

Some studies have started from a clean slate and just put a bunch of renewables everywhere. But that certainly is an approach and gives a ceiling on some certain perspectives. But the consistent framework needs to somehow be developed considering the constraints of the markets, the regulatory environment and also the technologies.

I think some of these studies do need to be updated periodically to take into account technology changes and leaps in technology, whether it be storage type of technology or other advanced generation that could be taken advantage of, you know, in the next five to ten years timeframe.

So, certainly, to a 2020 we can only do our best in our estimates today. The cost factors are based best on. As soon as they're out -- I've heard forecasts, as soon as they're out they're wrong. So we need to take that into consideration in making these decisions.

As far as impacts on the contractual delays and cancellations and how does California compare with other states, well, we're dismally behind. Considering all our very aggressive state environmental and RPS. We took the lead in the RPS; it was a very -- 33 percent target as a goal.

But the risks, as mentioned by Pam in her presentation, due to transmission and siting, those things are really hindering development, as well as any sort of developer incentives to come to the state. It's just too much of an uphill battle. Other states are even giving them statewide incentives to come and develop projects their states. So we do have a lot of competition out there from other states.

The other area, which is this retail price impacts. Again, this kind of goes back to the regulatory environment of our existing infrastructure, and not wanting to introduce unintended consequences into our operations when we switch.

We're kind of at a transitional stages and transformation from our current way of operating to adopting a lot of intermittent renewables. And the question was asked should we just incrementally do it or jump to it. And I think it must be done in some sort of a phased approach. Just for economic reasons, as well as looking at options of development it's taken, you know.

Optimistically it may be five years for some of these transmission lines to go into place. And then to gain the operational confidence we need to look at not only storage technology, but I mean that's to be developed, but also operator enhancements and tools for forecasting.

Because we still have to account, for the example of wind, is when it doesn't blow. So you need to consider all the available portfolio resources to really take these things into account.

As far as economic procurements from out of state, some of our transmission issues are local. They're not going to be resolved by having electricity imported from out of state. And if we're going to import a lot coming out from other states, we need to be cognizant of the fact that if it's not firmed coming into our borders, we're going to have to deal with it instate.

So, those are some considerations on the operational side to make it more reliable and sustainable development if we're going to attain 33 percent or any other future targets.

MS. DOUGHMAN: Go ahead, Dave.

MR. HAWKINS: Okay, I love it when you start talking about operational issues. I'm not bored then.

Let me start off by first saying that we really think we have to have a holistic view of this thing. And a holistic view is really a regional view, not just a state view. Because if you look at all of the western region we have tremendous resources that are being planned all the way from Wyoming through the Northwest area. And a lot of work going on with NREL in the whole southwestern area and looking at the development of that.

And certainly if you're Richardson in New Mexico, they are really looking to export some of that wind generation out of New Mexico to California. So we are a natural market for where the renewable resources are going to go.

And so if you look at, thinking about, first of all, imports are going to be a critical piece of this, not every piece of renewable has to be developed within California, itself. So I think we need to be able to use that, socialize that, bring in those lower cost resources from where we get them.

Second thing we have is that if you look at the climate change models, climate change says we're going to get a lot less snow pack in California. And a lot of that is going north. The impact of what will be, is when you're up in the Pacific Northwest and up into Canada, snow does not go through turbines very well. You really have to have snow melt.

And the snow melt, like this year, is going to come down at very rapid rate, and the reservoirs are going to be very full.

And so if you look at January, February up in those areas, they are going to have interesting problems trying to get as much generation as they need. And if you look at the fact that we could develop solar technology in the southwestern area, particularly southern California, we could tremendously export energy up to the area. And then, of course, take advantage of their additional hydro coming back in the summertime.

So I guess the first message is we really need to think regionally, as well as within California, as to what we're going to accomplish. And, of course, need the associated kind of green highway to move that in.

Second thing, going first of all, the first question, which is how do you count the 33 percent renewables. How do you do the math. And an important issue, it seems to me, is the fact that you really want to think about the photovoltaic impact.

And we've already talked about the Million Solar Rooftop Initiative. We're estimating that you're going to see anywhere from 3000 to 5000 megawatts of solar generation, which

I think really counts, at customer locations. And it's behind the meter.

So you say, okay, how do I count that in the equations. How do I go look at it. So, again, if you think holistically where we're going, we're also talking about smart grid and automated meter reading systems and so forth.

And if you think about how does AT&T know that when I'm in Portland or I'm in Atlanta, they still know how to bill me for, you know, all the usage I do on my cellphone. And so you think, well, gee, we probably could figure it out as to how to figure out how many megawatts are being used or generated by photovoltaics, as well as the amount of energy that we're delivering.

So my suggestion is, as we think about the 33 percent renewable goal, is that probably 5 percent to 8 percent of that may be behind the meter at the local retail locations, or the big box stores, or any of the other commercial buildings, which represents a tremendous opportunity.

Second issue that we have is we're also looking at trying to expand demand response programs. And the advantage, of course, of demand response is going to decrease the denominator in this case. So if you're looking at the amount of megawatt hours that have to be served, we certain could still take some of the megawatt hours off the table, which would also increase the amount of energy supplied by renewables.

So the grid, itself, may supply somewhere between 25 to 28 percent of the renewable energy. The rest of it should come locally. And I think if we think about the whole energy policy for the state, you really have to put all those pieces together. I think they're really critical.

Second part of the question is looking at the resource mix. And, of course, what we have coming out is part of the 20 percent renewables goal is dominated by wind generation. So you hear lots of impact studies done that says, oh, my gosh, what are we going to do with wind. How are we going to handle all the wind and the variability of wind. And that's because wind is the dominant one that's coming off first as the most cost effective and so forth.

We're absolutely, if we're going to go to 33 percent, we've absolutely got to have solar, got to have biomass, you have to have geothermal. It's the combined mix of all these resources which is really critical.

In order to do the operating studies you have to decide, well, how much do you have and which one of which. And it also makes a huge difference of where. Wind generation in one area may have a fairly low capacity factor. Wind generation in other areas may be much more steady.

We actually have seen wind generation in one area for a couple months of this year that had a 60 percent capacity factor. Substantially beyond the normal what we do a one-year average, which is in the low 30s or even lower than that.

And, of course, you look at areas like the Altamont Pass, which has the wind turbines, the old wind turbines, shut down for a substantial period of the year. And they have capacity factors less than 20 percent because they have to shut down the old units.

So we have repowering issues to do. So, it's location. It's like real estate, location, location, location. You got to find the right locations.

So there's a lot to do. In order for us

to do the operating impact studies we have to have some pretty good scenarios of what type of generation is going to be built, and what the characteristics are of those particular areas.

So in terms of research, analysis, and so forth, we still have a lot of work to do to get some of those profiles, models that we could actually then include as part of our overall studies.

The issues of contracts. We are not in a position to monitor contracts, so as the California ISO, that's not an issue for us. We assume that everyone is doing a great job of doing those.

Would like to make a comment, though, on feed-in tariffs, because what I've seen of the things that are showing up is the impediment, at this point, is not getting the contract done, but getting the permit to build something. And where, getting the location to build it.

So we have large solar projects that are all queued up now at BLM, and nothing being approved. We have other projects that, you know, looking for permits. Nothing approved.

It took us a long time to get our

transmission plans approved. We are building out Tehachapi for the transmission, but we still don't have the Sunrise Power Link or any alternative to be able to pick up a watt of that renewables in southern California.

So we have a problem in that the transmission and getting the permits are the big deal. And the feed-in tariff I don't think solves any of those problems.

If you look at Texas, Texas is moving ahead very aggressively. What they've done is they're very friendly, they're very supportive of getting all the stuff installed. It's not a big deal. They just finished their CREZ project, and this last week they announced that they're going for scenario two on their CREZ project, which then says they're going to build out their transmission to handle 18,500 megawatts of wind generation.

And everybody, you know, you're looking at where it's happening to all the units; where are they being delivered. Well, go to Texas. And it's because Texas says, y'all come on down now, we've got it onboard.

And so they've got a friendly process; a process that is not onerous in terms of their permitting and everything else, so that's where it's going. And the feed-in tariff doesn't solve that. I still think that that's not an issue.

So, anyway, in terms of pricing, you know, we're not in a position where we actually do the cost pricings types things. I think that really goes back to the Energy Commission and CPUC to look at those issues. But we will provide our inputs and so forth, as we go forward.

Thank you.

MS. DOUGHMAN: Snuller.

MR. PRICE: Thanks. I'm going to walk through each of these four questions and just provide a brief summary of what's in the GHG modeling and analysis that we did.

Before I do that I just want to acknowledge how much of the prior work that a lot of the folks on the panel have done that we drew from, the intermittency analysis project, the CRS study, the scenarios project.

I think, in particular, Mike Jaske was way too modest on characterizing the scenarios project just a few moments ago. It definitely helped us, I think, steer away from some of the potential issues in this type of thing.

In particular we took lesson and tried to create a tool that could do lots of scenarios. And gave that tool to different stakeholders and parties in the CPUC process so that everybody could run their own view of the world. And I think that's been helpful.

What we saw earlier today was sort of one reference case. And so when we go to questions like resource mix or what-have-you, recognize that's just one reference case, and that actually you can do a lot of different things within that.

I think that sort of going forward the one area that we're headed to and that there hasn't been a lot of work done on is really feasibility. Okay, so feasibility of 33 percent. And I'm not talking just about the engineering, although that's a critical part of it; I'm not talking just about the economics and whether we're willing to spend the money, although that's also a big part of it. But also process.

You know, our processes for siting new facilities; where are they going to go; how are we going to get that all hooked up. And looking at the timelines. 2020 is actually not that far away. Our shop has been involved with the ISO on siting of the Sunrise Transmission Line. I think that project has been about seven years or something like that.

So, if we continue to take seven years to do each transmission line, what-have-you, 2020 starts to really catch up with us quickly.

So with that let me try to just quickly go through some of these questions. The estimating 33 percent of retail sales. I think the key thing that we're getting down to there is the forecasting, and trying to get out our crystal ball and forecast what retail sales will be in 2020.

Clearly in our analysis the big drivers are energy efficiency, and what do you assume on that. Photovoltaics, to some degree; combined heat and power and behind-the-meter generation is also a really big chunk and driver of that uncertainty.

And then I think our panelists have mentioned a couple of times electrification; both the transportation sector, gasoline-to-electric, but also industry as fossil fuels prices increase.

In terms of comparison of resource mix

scenarios, the analysis that we did was primarily focused instate. I think we had some Mexican wind in our sort of 33 percent scenario, but mostly instate resources. And that was by design. I think the resource mix you get looks really different if you go to broader regional look. We tried to put the tools available to do that, but our reference case scenarios didn't.

I think the other thing that you get to when you look at these analyses is that we're doing sort of least-cost, what resources generally are lower cost and putting those in first. But we have to recognize that we have a whole renewable procurement process. So our utilities are issuing calls, and they're getting back bids and projects that they don't actually necessarily control.

So, while if you're using the GHG calculator or another tool, it's kind of fund to say, okay, we're going to do Tehachapi, Imperial Valley and what-have-you, that may not be what we get. So there's this whole procurement process that we, you know, -- and that's a good thing, I think, more competition, but something to keep in mind when you're playing or looking at one of these resource mixes.

Impacts of contract delays or cancellations. I think on that one do I think that the current procurement process will produce 33 percent renewables by 2020. I think we could probably get contracts for 33 percent renewables.

I am less optimistic without changing the way we do siting, planning and actual construction, that we'll get the megawatt hours or gigawatt hours, as the case may be.

And in terms of, you know, whether California's losing ground, I think, you know, Texas is the example where we did a recent chart and, you know, their addition of new wind generation is just far outstripping ours.

In terms of potential wholesale and retail price impacts, and I think one of the things that we really tried to do with our GHG modeling was to estimate, by LSE, both public and investor-owned utilities what's going to happen to consumers through retail prices.

So it was a little bit sobering when we saw some of the results. We think that retail prices are going up sort of regardless of what we can -- all scenarios prices seem to be going up.

And in our 33 percent reference case

they're going up more. Although if we can get enough energy efficiency then ultimately consumer bills may not increase.

So the question is can we get enough energy efficiency to fund our renewable investments. I think we saw a percentage, something like 5 percent or something like that in terms of retail price increase through a 33 percent relative to a just sort of an existing policy 20 percent case.

So with that, I think I'll pass it along.

MS. DOUGHMAN: Go ahead, Jaclyn.

MS. MARKS: First I'd like to thank the CEC for the opportunity to speak on this panel today. And unlike the other panelists here the PUC has not yet conducted a study on 33 percent renewables. But we will be conducting a staff analysis as part of our long-term procurement proceeding in our 2010 long-term procurement plans.

The CPUC Staff analysis will be a key input that will direct the IOUs, investor-owned utilities, on what the PUC views as a realistic RPS scenario in 2010. And that will be, in a sense, a reality check on whatever the utilities come back to us as their preferred resource plans.

So just, I'll briefly describe what we intend to do for this 33 percent staff analysis. And we really see two parts. I think a lot of the panelists and Pam and Suzanne have already touched on a lot of the elements here, which really shows how critical they are.

And the first part of the staff analysis will be to do a cost and resource buildout scenario. And we intend to do this by early February of 2009.

And this resource buildout would use data coming from the Renewable Energy Transmission Initiative which will, at a project level, describe what the renewable potential is across the state.

It will also have updated load resource tables which will come out of the work Snu and E3 is doing in conjunction with the long-term procurement plan proceeding. There's a assumptions and metrics working group that is going to be updating these numbers for the investor-owned utilities.

And then a third key input which we

actually don't have yet is the integration cost data, and, you know, ramp and regulation numbers. And I know we're going to get into this more in the afternoon, but this is really a critical piece to calculating what the resource buildout will look like.

And I think David said, well, we need to know what the generation will be; and I agree. But we also need to know what the integration numbers will look like. So need to work in conjunction to have that data ready.

And this first part will come out with, you know, a resource buildout and some cost estimates. But as the other panelists have emphasized, costs now are extremely uncertain. There's a lot of policy uncertainties in the future and, you know, your model can come up with a number, but we're not sure right now how much we can depend on those numbers.

So our focus for part two will really be on implementation scenarios. And the other panelists have also touched on this. The problem with bringing more renewables online isn't necessarily the procurement process. The PUC has signed or has approved over 5900 megawatts of contracts. Of those, about 4500 are for new projects. And since the program's inception only about 400 projects have come online.

So the problem clearly is not signing contracts. The procurement process is working. This goes to question three. And we had independent evaluators -- we had three independent evaluators for each utility which oversee the RPS procurement process. And we had them put together a memo for the energy division of the PUC on how the procurement process for renewables compares to fossil within the state. And also to renewables within other states.

And their main message was the procurement process in California is working. It's very streamlined; it's no more complicated than other procurement processes for renewables in other states. And it's, in their view, even more streamlined and predictable than the procurement process for fossil in the state, because every year you have the same expected procurement process.

So, it's not the procurement process in the PUC's view. It is the permitting, it's the transmission, it's the site control, it's all of these other agencies that play a role in bringing renewables online.

So that's why part two of the staff analysis is going to focus on what does it physically take to reach 33 percent. And who are the key players and agencies that have a role in making that a reality. And what can the state do to actually overcome these barriers.

So that's really what the focus of the staff analysis will be by February of next year. But we also envision a phase two which looks at policy uncertainties beyond 2020.

And all the other panelists have already mentioned, there's all these uncertainties around emerging technologies, electrification, smart grid, the impact of rooftop solar photovoltaics. Those are all key inputs into this analysis today, but are very uncertain.

So, that is not something we will be doing in phase one, but we are considering for phase two, or perhaps coordinating with the IEPR process to do that type of analysis.

And so I believe I've covered most of the questions I was going to cover. But just to see if I missed any, 1b says any suggestions on how to estimate 33 percent for statewide retail sales.

Well, I can't help statewide, but at least on an IOU basis the long-term procurement process will be coming up with estimates for 2020.

And, let's see, 2c, what assumptions should be made in coming up with a reasonably likely resource mixes for 2020. I think a key input there is the ready data, the data from the Renewable Energy Transmission Initiative. And also the staff analysis that the energy division will be coming up with.

And three, I went over this already, but it's not the procurement process, it's the implementation process. And that's why the PUC is really going to focus down on that issue.

And d, what could be done to increase the rate of new renewables is really all of the state agencies working together, the state, the local, the county, whoever it is, work together, collaborate and overcome those various barriers to bringing projects online. And that's something that the PUC intends to do, and has already started with ready and with working with the BLM on permitting issues, and the CEC.

MS. DOUGHMAN: Go ahead, Jan.

DR. HAMRIN: I'd like to just respond a bit on the feed-in issue, and why I think it would be a benefit.

The reason is that when you do the RPS procurement as we're doing it, you've said, okay, we're going to take these projects, we're not going to take these projects.

And one thing we've learned is that we're almost always wrong about all kinds of projections. And I've certainly heard from some people, whether it's true or not, well, I had a project, I have a transmission, I have permits, I could have built it. But I got turned down in the procurement process.

If you had at least some portion of projects that could come through a feed-in tariff you could be surprised. There could be projects that do have transmission, or that could get permitted that you hadn't thought about.

And, again, harkening back, as I think I'm allowed to do, to the old days in the 80s, we never would have projected the mix of resources or the kinds of technologies that we ended up getting. We didn't know what we were going to get, but we thought we did. And we're almost always wrong. We'd have something come in, go, oh, gee, we never thought about that. That's interesting.

Getting generation from rice hulls. That's something we hadn't thought about. Or all kinds of different technologies came forward. And I think innovation is one of the benefits of a feed-in tariff. So, you may not go to a total feed-in tariff, but I think allowing, you know, a million flowers to bloom and seeing if there's people who actually, because of the particular location, or the size of the project, or the kind of technology, happen to have, be able to get transmission and can get their project permitted because it's part of an agricultural development that has a lot of support locally. Or other things of that nature.

I'll just end it by saying that, as you know, Center for Resource Solutions does the green-e program. And that is primarily looking at renewables for the voluntary market.

Well, it turns out nationally one of the voluntary renewable energy market has actually resulted in as much or more renewable energy brought to the market, new renewable energy projects, than the RPS projects have.

That doesn't mean the potential for RPS isn't much bigger. It certainly is. But, the voluntary market has actually delivered. Partly because, I think, they haven't had to go through quite as many hoops and barriers.

Twenty percent of the national voluntary market is being sourced from California. Now, I've had people tell me, well, that's not possible because we're signing contracts for all the renewables that are there and they haven't come onboard.

Well, there are people out there who are building projects and they're selling to other buyers, including the voluntary market for renewables. And they're located in California. And they have at least as many megawatts, I believe a few more, that they brought online for that purpose than has come online for the RPS.

So, I think having an opportunity for people who think they can do it another way, to do it, is useful to have somehow in the process as you move forward.

MS. DOUGHMAN: Mike Jaske.

DR. JASKE: One of the common themes that various of us have identified is uncertainty. And it's certainly highly desirable that where there's -- those are policy uncertainties that we take them into account.

So, for example, in the current RPS formula, taking predicted energy efficiency into account is important because that's, you know, intrinsic in how the retail sales obligation is defined.

But, it seems to me we, in cataloging the various sources of uncertainty, we are sort of revealing, at least to my mind, the issue of whether we ought to separate out the sort of policy level discussion about those interactions, and therefore the amount of renewables we're trying to target, versus continuing to use that formula for every individual load-serving entity, which at their level has all the same uncertainties, and even more, like load shifting between LSEs. It's certainly important from the ESP and the host IOU perspective.

And those are things that tend to lead to, you know, paralysis of just what is the amount I have to go for, I, the individual LSE, who's making a procurement decision.

It just seems like an unnecessary incorporation of uncertainties into the implementation side of things that is best focused on at the policy level; translate that into magnitudes of renewables that should be pursued, and then let that go forward.

MS. DOUGHMAN: Dave, did you want to answer?

MR. HAWKINS: Well, the one thing I forgot to mention was the, what we're really looking for, too, is building the nighttime loads to match some of the wind generation.

Our expectation at this point is that the transportation side is going to come to the rescue and that we will see plug-in hybrids. And we're expecting that hopefully, within five years, we'll see 500 megawatts of load come on at night. And certainly by 2020 hopefully that'll be up to 1000 megawatts of nighttime load.

The big issue is going to be to make sure that we set standards in place so that there is either a tariff or something that encourages them to not all just get home at 6:00 and plug in. But that we actually have a schedule-able load that would come on in the middle of the night. And particularly if we could send out a signal from the wind generation site, or to say that excess wind generation's currently available where you would see this loads come up.

So, the whole idea of trying to connect customer loads with some of the variability of renewable resources, we think, is going to be a key issue.

Certainly if you look at smart grid type things and plug-in hybrids, you think that those things are achievable. So, back to the research and development side, I think we need to build some of these communications infrastructure to make, again, this stuff work together as a whole.

Thank you.

MS. DOUGHMAN: Any more comments from the panel?

Okay, blue cards.

(Pause.)

MS. DOUGHMAN: Last call for blue cards on topics 1 through 4.

Okay, let's break for lunch and come back at 1:00.

(Whereupon, at 11:53 a.m., the workshop

was adjourned, to reconvene at 1:00 p.m., this same day.)

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AFTERNOON SESSION

1:04 p.m.

MS. DOUGHMAN: We'd like to go ahead and get started again. Just want to remind you if you'd like to make a comment, please fill out a blue card. And we have some staff who will be standing up and asking for you blue cards. Or you can hand them to Donna Parrow. And we welcome your comments.

Okay, so the plan for the afternoon is to go over topics 5, 6 and 7. And for topic number 5 we have presentations from a number of our panelists. And then topic 6 I'll have a brief presentation, or actually topic 6 is more of a lengthy presentation. Topic 7 is a brief presentation.

And then we'll have our panel discuss their perspectives on the questions for topics 5 through 7. And then we'll open it up to public comments.

So, that's the plan for the afternoon. So, I'd like to welcome Dr. Jam Hamrin to talk about, so what's new, an update on achieving a 33 percent renewable energy target.

DR. HAMRIN: Thank you, everyone. Try

to make this as painless as possible. So, we're sort of the old, appropriate again, the old guard on doing, looking at this question. We did the first one, I believe, that anyone looked at.

And so the report goal was how to accelerate and expand the current 20 percent RPS. And pretty much the goal we're talking about today, to achieve the Governor's 33 percent goal by 2020.

So, interestingly, most all of the operational and other changes we recommended in the report are still relevant. Many have already been undertaken. I have to commend the CPUC for really going down the checklist and putting in place a number of changes before we even got the report out the door. And others are in process, but still others need attention.

This was primarily a scoping document to look at the technical and economic feasibility of moving from 20 percent to 33 percent RPS target. And as was mentioned earlier, because this was done for the CPUC we looked at the investor-owned utilities.

We did not use a computer model, we used spreadsheets. So there was no mystical anything buried in the bowels of a computer model, it was just plain spreadsheets. Those have been posted on the PUC website. Now, I don't know if they still were there or not, but, again, similar to Snu's comment, you could take them and change the assumptions and see what the effects would be.

So if they aren't still on the PUC website and you're interested in it, we can see if we can get them back on. So it's just a spreadsheet, very large spreadsheet, but spreadsheet kind of analysis.

The results, it was both technically and economically feasible. And would likely result in net savings to California electricity consumers over a 20-year period. Under the assumptions that we used, there'd be a small negative ratepayer impact, 2011 to 2020. And that was less than 1 percent negative ratepayer impact.

But it was more than offset by the longer term ratepayer benefits. From 2011 to 2030, the net savings, we estimated, would be in the area of 175 million. That is not a lot of money when looking at utility costs; and certainly is probably within the uncertainty band for many of the assumptions that went into this.

Data uncertainties. The two most critical variables, needless to say, were renewable energy cost forecast. What were renewable energy facilities going to cost us, and natural gas forecast. And natural gas forecast will remain, I'm sure, being the controversial area because we were comparing 33 percent renewables to having more natural gas. That's what we decided was on the margin and that was the bogey that we used.

Obviously transmission costs are also important. And those have also gone up. Though they tend to affect all new supply, since California transmission system, in general, needs new lines and upgrades to lines. So many of the things were network benefits.

However, we added 50 percent to the cost of renewables for the transmission costs that we estimate.

Integration of intermittent resources like wind and solar were also important. But at the levels we're discussing, those costs didn't seem to be prohibitive and we put in $5 per megawatt hour as the -- for our placeholder for the cost of integrating intermittent resources.

Most the other variables affect all generation technologies. We did not do line losses. There would be line losses for the fossil as well -- natural gas as well as the renewables. And we just let that go as one complication we didn't need to put in.

And many of the variables would affect all generation. So, it was really the key things were what would renewable energy cost, what would the natural gas forecast be.

So, what's new. Well, renewable energy costs have gone up by much more than we had anticipated in the study. Wind has gone up. This is just eyeballing some recent data that we've gotten, about 30 percent geothermal, about 50 percent solar, concentrating solar about 25 percent, not sure about biomass.

On average I'd say the renewable costs are about 36 percent above what we assumed in the study.

Capital cost of natural gas plants has gone up by 100 percent. Now, granted the capital cost of a natural gas plant is not proportionally as large a cost factor as the capital cost of a renewable plant.

Still, capital costs have gone up 100 percent for natural gas plants based on the latest Department of Energy information on combined cycle.

Natural gas price forecast has gone up significantly. How much? That's something that could be -- is still to be debated. I would say at least in the 30 percent range.

There is a report from the Department of Energy. If you haven't seen it, you might like to. This was their report to the FERC, Federal Energy Regulatory Commission. It was given June 19th of this year in Washington, D.C.

The bottomline is that the cost of everything has gone up and is continuing to go up. And natural gas is one of those that they don't expect to come down.

The cost of renewable energy compared to the total cost of all other generation options; actually renewable energy is looking more cost competitive today in many cases than it was in 2005.

The cost of coal plants have gone up tremendously. The cost of everything, nuclear plants, have gone up tremendously. So that compared-to-what is a really important question.

We'd like to see the calculations and the analysis redone with the latest data. It'll be interesting to see what we get. But we believe that you're going to get very similar results to what we got. So it's just the bar will have gone up for everything. But I think you're still going to see it in a range that is pretty close to what will happen with natural gas. And with all the uncertainties in the data that it's certainly is right on the error margin.

So what else is new? Well, as we discussed this morning, California is off target in meeting its 20 percent RPS. The impact is though the relative cost of renewable energy gets lower, the longer it takes, the more new supply is going to cost California consumers. That's just how it's going to be. It doesn't matter what it is actually that you're putting in the supply side, it's going to cost consumers more.

And we estimate that it costs 1.5 percent of the value of the power purchase agreement of the contract per month of delay for any particular project. That is a big premium, a big risk premium.

So, as we were talking earlier about the possibility of using a feed-in tariff, strategically in certain areas, maybe you could have one where you add premiums based on how soon you can come online. Because, in fact, it will cost California's electricity consumers a lot of money the longer they have to wait for these projects to come online.

You'll see this message through the rest of my few slides. The longer you wait, the more it's going to cost you, no matter what you're doing.

The big change in context. Well, the obvious big change is the greenhouse gas goals for 2050 indicate the electricity sector will need to make major changes. The passage of AB-32, which happened since we did this report, puts the whole context in a different place.

And the changes in supply and structure are going to be needed in the electricity sector. Not just reductions in emissions from existing fossil plant. You cannot get to these greenhouse gas goals simply by pressing down on the emitting generators. There's no way you can get there.

You have to change the infrastructure,

change the types of resources you have in your mix. That's the only way you're going to have any chance of meeting these goals. The longer we wait, the more it'll cost consumers.

And just for your information, our 33 percent report did not include greenhouse gas allowance cost for natural gas plants to meet greenhouse gas targets. So that was not included in any of our calculations, but certainly one would want to be included today.

One of the problems with greenhouse gas controls as compared to, say, acid rain or NOx, is that we don't have technical fix that's economically available today for a power plant to put on its stack. To put a bag house, to put widget to do something that's going to shut off the carbon. We don't have it.

So, therefore, all the emitting facilities can do is either get all the allowances they need or quit generating, or turn back their generation. As a result they are going -- normal or natural reaction, they're going to constantly be fighting any ratcheting down of greenhouse gas caps because they can't -- they have no place to go. It's not like they could go out and buy something and put it in. So this is going to be an increasingly larger and larger problem.

So what are the AB-32 options for the electricity sector? So I want to come at this from the other side. What would you do if you didn't do the 33 percent renewables, or even more?

You could do more natural gas. Fuel price volatility risk is not insignificant. We've got a large proportion of the state's generating power already comes from natural gas plants. How far can we raise it without adding tremendous cost to the system because of lack of diversity.

Overall, natural gas prices are going up and up. Unbalanced portfolio, as was mentioned earlier. You need a balance in your portfolio, and so putting more and more resources into the natural gas is not the way to go.

And greenhouse gas allowances, natural gas is much cleaner than coal, but it is not without emissions. And there is a cost associated with those, and you can't just add more natural gas as your way of meeting AB-32.

Nuclear. The latest estimates in Florida for the new nuclear power plant there is $8000 to $10,000 a kilowatt. That makes renewables look like a heck of a deal. And this was reported by Florida Power and Light and by Nucleonics. This wasn't my number.

You also see it in the DOE report that nuclear prices are through the roof. This is not counting fuel, not counting decommissioning, not counting any other costs of handling spent fuel, any of that. This is just the capital cost of putting in a new nuclear plant.

In transportation, as we mentioned earlier, you might go to plug-in hybrids or hydrogen. With buildings you may see some switching to ground-source heat pumps or things of that nature, all of which will drive up the demand for electricity.

The last options require clean electricity supply. It doesn't make any sense to go to plug-in hybrids or hydrogen if you're going to have a dirtier electricity mix. You have to have a clean electricity mix in order to have that make sense in the greenhouse gas context.

So, what are the options? Well, over the next 10 to 15 years, and that's the critical time, so if you've heard any of the discussions, if you're listened at all to the discussions on climate change you know now is the critical period. Whatever we can do now will cost us less. If we wait, we go over tipping point, and we may have catastrophes that we can't do anything about, and the costs will be much, much bigger.

So what have we got? We've got energy efficiency and conservation, and we should be doing every bit of that that we possibly can do.

And we've got renewable energy. That's what we've got today.

Regardless of your future technology preference, if you wanted nuclear you could not get a nuclear plant built in a ten-year time window. If you wanted hydrogen you are not going to have that technology perfected in the next ten years.

If you wanted clean coal with carbon capture and sequestration, you are not going to have any amount developed in the next ten years. Not counting the fact that we don't know what any of those technologies are going to cost us.

Somehow we always have this, the less we know about something the better it looks. And so there is a temptation to really hope that there's a technology fix out there someplace. And there may well be, but I think in the next 10 to 15 years we have to do energy efficiency and renewable energy.

That's what we've got. And we can do it if we have the political will. And if everybody is working from the same agenda. That's not always true, unfortunately. But that's what we need.

The key renewable implementation issues, transmission line construction, administration, we just have to get those transmission lines up and going. And we know that siting anything is difficult. Siting at a national park is even more difficult. Maybe you need to look in an alternative path. But transmission, transmission.

We've gained some momentum among transmission. The ISO has done an excellent job in changing a lot of their rules and looking in their planning side for ways to accommodate the renewables that are required by law. And we need to keep that momentum going.

We need to, as I said earlier, streamline the RPS procurement process and maybe find a way to strategically have a feed-in tariff for innovative technologies, for projects that can come online rapidly because of their location or other reasons.

We need to be thinking creatively and not just think about the way we've done things before, including the feed-in tariff. We need to think, well, creatively, if we put a feed-in tariff in, if it costs us 1.5 percent of a total contract value per month that they're delayed, then maybe there's a way that the consumers could offer a premium for coming online sooner for those projects that are able to do it.

But if they get the same price or lower price, as brown power, then the feed-in tariff probably isn't going to do a lot of good. But I think we can think creatively and I think we can come up with answers that'll be helpful.

Remember California's in competition with other western states RPS programs and greenhouse gas reduction programs. If I'm going to build a project, do I want to sell it in California; do I want to sell it to one of the other neighboring states.

There's a lot of consideration goes into that. And the data I mentioned earlier about the voluntary market and how 20 percent of that market's coming from California indicates there's people who have decided not to sell into the RPS structure.

There are lost opportunity costs to utilities of implementing more renewable energy. We need to keep that in mind because, though not purposely, it does influence rapid movement. There are benefits to some utilities of not moving things along as rapidly as they might move.

And you can't blame them for that. It's built into the structure of how we do utilities, how we do utility rates and other things. Nevertheless, we can't let that get in the way of everything.

So, the PUC, I think, still needs to clarify the impact of RPS noncompliance. And supposedly there are fines there, but under what circumstances would fines actually be levied. Or will anybody ever have to pay any. It would be good for everyone to be clear on exactly what delay means.

Otherwise, if noncompliance costs utilities nothing, delay is inevitable. And that's just a fact of life.

So, in summary, since 2005 the cost of

all supply technologies has risen as much or more than the costs of renewable energy, technologies has risen. The state has been slow to achieve the 20 percent RPS, but neither factor provides a reason for not moving to 33 percent RPS.

Renewable energy is as good or better investment today than in 2005. The longer we wait, the more it will cost California's electricity consumers. The high-cost path is to have no 33 percent RPS.

Thank you.

MS. DOUGHMAN: Okay, our next speaker is Mike Jaske.

DR. JASKE: Thank you, Pam. Despite what the agenda says, I'm actually going to focus on the subject of resource adequacy and how that affects renewable development, which I think is a dimension of the sort of regulatory planning structure that's been under-focused on up to this point.

So do some things, just give you some background about what resource adequacy is all about. Talk about this concept called net qualifying capacity -- there's some letters missing there -- and implications then for renewable resource development.

So, from the ISO's perspective, you know, its reliability responsibilities have to be primary over everything else. And the ISO has been pushing for a mechanism that allows it to commit and dispatch generators when, you know, market forces don't bring the right resources to bear. And this frequently happens under some sort of contingency circumstance, not just, you know, normal operations.

We've been getting by for a long period of time now with the June 2001 FERC decision that, you know, sort of brought some order to the California crisis of 2000/2001. But that's going to go away, scheduled to go away with the MRTU implementation. And new mechanisms are being designed to substitute for this thing, going by the acronym, MOO, must offer obligation.

So, the ISO has a tariff that creates resource adequacy requirements for all the LSEs, load-serving entities, in its balancing authority area. In that construct there are entities called local regulatory authorities which are essentially the governing board over a utility or was influencing another form of entity.

And there's a whole lot of default mechanism in there if these local regulatory authorities fail to put together the right pieces.

The PUC is the local regulatory authority for the three IOUs, and for the remaining 11 ESPs. We lost one ESP as of the middle of this month.

AB-380 came along in year 2006 and clarified that the PUC did have resource adequacy control over ESPs, which some ESPs were sort of contesting up to that point. And also gave some statutory direction to the PUC about what it was supposed to accomplish through a resource adequacy program.

And that legislation also gave the Energy Commission some very limited oversight over the publicly owned utilities, essentially dealing with collecting information about what they were doing in terms of resource adequacy, seemed to be sufficient, and then to report that to the Legislature, which we have now done one time, as a small piece of the 2007 IEPR and a staff report behind that.

There's two parts to resource adequacy. There's thinking about it from the system level and the local level. So, let me focus on system level. First of all, there's a requirement for every month, all 12 months of the year. Every month is treated individually, with some limited exceptions.

The May through September months have special provisions and each LSE has to provide a showing how they're satisfying that May through September set of months on what's called a year-ahead basis.

So, in the fall each LSE will file something for all of this year, each LSE will file something for all of calendar 2009. So that's why it's called year-ahead. A few months ahead for January and 15 months ahead for December.

And then as you go into every individual month of the year, there's a month ahead showing which sort of brings the whole package together. And there's generally a filing 30 days ahead of that month where you have to show the totality of your requirement being satisfied.

The PUC and ISO go through and they check these things. They verify that the generators that are identified in those filings are, in fact, available to them. And they are going to become the only generators that the ISO can commit and dispatch.

And at the moment we still have a few, well, until MRTU takes effect, we still have the FERC must offer obligation on all generators in the ISO control area. But once MRTU takes effect, only resource adequacy generators will be dispatchable by the ISO, except under some other very extraordinary conditions.

Actually -- oh, it's to distract your attention. The focus of the word system is on a resource -- the resources that satisfy a load-serving entity's load wherever it is in the ISO control area.

So, if your strategic energy is an ESP version of an LSE, and you have, you know, X hundreds of megawatts of direct access loads scattered around California, you have an obligation to produce resources that cover that load, plus the 15 percent.

For the system purposes, you don't have to link the physical location of your load with the physical location of a resource. And, of course, any other generators -- or any other load-serving entities don't have that kind of local specificity requirement for the system.

Local is the complement to the system, and it does do precisely that. Ties where the load is to what the resources are that can actually serve that load, given the fact that the transmission system has constraints, and that there's this thing called load pockets.

So there are ten load pockets that have been recognized by the ISO at this point, given the nature of the transmission system. The ISO does a technical study every year to determine, given any transmission system changes, and perhaps load growth, what is the minimum amount of generation within that load pocket that has to be secured by all the LSEs that have load in that load pocket.

It does that by examining peak demand at a one-in-ten condition. And so this is a summer stress to the system. And that level has to be satisfied across the entire year.

These local requirements, in effect, are the first tier of satisfying the overall resource adequacy requirements. So local has to be satisfied first, and then system. So, local requirements can only be satisfied with a limited number of local resources. Those local resources can also count for a system to the extent they're available and the LSE chooses to use them in that way. But not vice versa.

So an entity -- well, let's take San Diego, because I see Rob sitting in the audience. San Diego has a certain obligation for local resources, even though it might like to procure generators in northern California, it's limited in its ability to do that by having to satisfy its local obligation with local generators first.

This is just a picture that shows you what these LCRs areas are. And there are some intervening areas, so there's the sum of all the loads in the local areas is not the composite of the entire ISO.

And Big Creek Ventura one, which is sort of pink cross-hatched, that was actually added for 2008. It hadn't been recognized previously. So that's the basic overlay of what resource adequacy is.

Now, that qualifying capacity is the concept of, at its broadest level, how do you count the capacity of resources in this context of a resource adequacy construct aiming at reliability.

Most generating technologies at this point have a single value, is a dependable capacity kind of number. It's used year-round. Some technologies, wind and solar, without backup in particular, have monthly values based on the variability of their performance. And those numbers are updated periodically.

They're updated in this way. There's a data from the preceding three full years. So there's this rolling three-year averaging process. It takes the data on actual hourly production during the noon to 6:00 p.m. period, because that's what's relevant to peak.

And if an individual wind or solar facility doesn't have sufficient production history that their own numbers can be used to calculate their unique NQC, then there's a protocol that says you use the average of all of the facilities in the transmission area. And gradually roll in its CD data and roll out the average of all the similar resources.

The Energy Commission Staff has the function of updating these values annually, which we have just about completed for the upcoming 2009 resource adequacy compliance year.

And as Jan was indicating, there are some merchant wind projects out there that, although, of course, the great majority of these are still QFs or a few new RPS projects.

So here's an idea of what these monthly NQC factors look like. I'm reporting here in the sense of this derate relative to nameplate. So these are actually the values that for 2009 will be applied to any new wind machine that doesn't have its own production history.

Green is the northern area; blue is the Tehachapi, San Gorgornio on south area. And you can see there is both a wide variation in the average onpeak performance from month to month. And quite a bit of difference between northern and southern resources.

This is the kind of variability that was brought to the PUC back at the inception of the resource adequacy process in 04 and 05, and it is embedded in the current requirements.

Now that we've had some level of experience in counting wind and solar without backup in this manner, some parties are now raising questions about whether that level of treatment is actually exceeds the true performance of these resources at peak.

And the ISO, in particular, has been pushing for what it would call more accurate formula. This was tackled, in part, this spring, but was so controversial that it has been postponed. And the current formula is going to be continued for calendar year 2009. So if anything changes it won't be until 2010.

This is a chart that helps to explain why it is there's concern. What we're looking at are the hours from 1200 to 1700 on a July day. This is the average for all the five years from 2003 through '7. This is for all wind machines in the ISO control area. And these are megawatt hours per hour, so that's, in effect, the average output of the facility as the vertical scale.

The dashed line across the very center of the graph is what the current NQC formula would provide. So, somewhere around 480 megawatts.

The blue line close to it is the individual hourly data for those same facilities. So average of those and the individual -- well, actually just the average is for the last three years. That's the actual number that will be used in 09. The blue line is the average of all five years. And so there's a little bit of difference between the average of the last three versus 05, but it's very very close.

The red line is what is the subset of days that were extremely hot and it exceeded a certain temperature maximum associated with the peak forecast.

So here we get to the crux of the problem. The red line is below the current NQC formula, the dashed line, in every hour, although it is rising as you get toward hour 17, and the peak is somewhere around hour 15 or hour 16. So it's closer there than across the entire six-hour span.

Some people would say this is an argument to reduce the value. A counter argument is that there is a lot of variability even in those seven peak day observations. And that's what the blue shaded envelope is.

So even though there's only seven observations making up the red line, they have so much variation that they are the shaded blue envelope around the red line.

So this is the dilemma. There is just

so much variability in wind performance at peak, which of course is the time when the ISO needs these resources the most, that we need a more sophisticated method than just this averaging technique. And later this year, phase two of resource adequacy process will start up again and try to tackle this with who knows what consequence.

Here's the nexus with local resource adequacy. The PUC just adopted ISO's number of just short of 28,000 megawatts. Hardly any of the renewables are in these load pockets. So, a RPS strategy or another renewable strategy that places more and more weight on this is, in effect, creating resources that are outside of the load pockets.

Strategy to deal with this is different from the overall system operation perspective that Dora in the IEP, or that Dave in the ISO's other study, you know, are going to talk about. They're talking about things that the overall system can do in order to deal with the hour-to-hour, or even within-hour kinds of variations.

This is a time horizon associated with planning. It has to do fundamentally with that one chart I showed you about how resources differ over the course of months that leads to a different or complementary set of resources that go along with renewables.

And they could, and they need to be ones that can be dispatchable at peak, because that is the essence of what resource adequacy is all about.

You have the irregularity of wind machine output, or the predictability of the nonoperation of solar without backup to deal with. As both of those become bigger and bigger pieces, if they interact with shifts where system load is, to build load in offpeak periods, we have to be able to have some sort of technology that will either both deal with these sort of holes in the production of the whole system, or deal with the contingencies that a transmission line goes down or some other dispatchable resource becomes nonoperational.

And the obvious things that one can think of are combustion turbines, or some kind of storage devices in much more massive scale than exists anywhere now, on both a daily basis; and to some extent, on a long-term basis.

So, that is the challenge that resource adequacy presents for the whole class of renewable technologies. There aren't well-developed methods for projecting resource adequacy requirements out into the future. And when we do our panel discussion later, I'll explain a little bit about how the scenario project tackled this. But this is a dimension of analysis that needs much more work.

Thank you.

MS. DOUGHMAN: Thank you. Our next speaker will be Dora Yen Nakafuji. She will talk about the intermittency analysis project.

DR. NAKAFUJI: All right, moving along. This might be a little bit of a repeat for some folks who followed the IEP process in the previous years. But I wanted just to highlight this was a project that resulted from the collaboration of many industry folks, along with utility collaboration in order to gather the information from both the transmission planning, as well as the operational perspective.

So, in terms of looking at operational contingencies and transmission planning reserves and contingencies, the IEP did consider those issues as part of the location and the integration of renewables.

Intermittency analysis project really was focused on high penetration of wind with some solar resource impacts. And derived from the RPS, the targets were essentially set based on the policies at the time.

As mentioned earlier that we have policies that are continually moving, and also regulatory environments and markets that are also changing. So, this is kind of the snapshot of where we were at that time.

And it presents kind of a perspective of where we're going to grow. I mean in order to meet 33 percent you can see what our gap, and some others consider that as opportunities, may be. It doesn't say what portfolio mix of renewables or other resources or other energy efficiency methods we should incorporate. But it does say these are the opportunities.

Some of the questions we attempted to answer and consider, and that was brought up in various groups, was what is the system going to look like in order to adequate dispatch some of these resources. So we had to come up with some perspective on that.

And what is needed for the grid to accommodate both an infrastructure market and regulatory and technologies. I won't cover all of those other topics, but we did look at international experiences, too. We reviewed a bunch of countries that have significant level of renewable penetration, specifically wind. And did a review of both their electrical infrastructure, their market and their regulatory environment to consider things that California could adopt, given our system.

And what were the impacts of increasing renewable energy penetration on system reliability and dispatchability.

So the IEP really focused, and it drew from a CEERT study that was done previous to, I believe it was the 2000 -- it was the year before, 2 IEPR, or 2000 -- but there was a CEERT study that was done and it's listed in the documentation as part of the package.

But really the CERT study focused on operational needs, operational impacts dealing with renewables. So, these are some of the categories that were highlighted in terms of defining attributes, reducing uncertainty, focusing on some of the policies and how do we plan, what are the planning tools we may have to consider.

The way IEP approached it was in addressing some of those attributes, we needed to come up with these performance curves. The technology traits in order to understand how do we even consider those generations on our current system.

Reducing uncertainty. We needed to have a consistent dataset that looked beyond just one year. Multiple years to capture the seasonal variations of some of these technologies.

And the transmission dataset, that dataset that's vetted and adopted within the industry, and that the industry is comfortable with.

Resource policies, looking at lessons learned, worldwide experiences, and what could potentially be adopted in the California infrastructure.

And improving planning tools. So, through this exercise we developed some tools that allowed all of us who are not all utility transmission planners or operators, to kind of get a sense of what their operational environments are like, and what their challenges are day-to-day.

Most of all I think IEP provided a common perspective. Again, to give all of us who don't deal with the dispatch requirements or the planning requirements of the utility, or at ISO, a sense of some of the concerns and a sense of some of the constraints on our system.

So it certainly was a step in that direction. It certainly didn't answer all the questions, but it started to formulate that consistent base of data so that other studies could be drawn from or consistently built upon. Because it, again, is a snapshot in time and that this needs to be periodically done as transformation occurs on the system.

This essentially are the scenarios that, based on industry discussions, we knew that there were current activities being pursued in certain regions. Southern California. So we looked at a significant amount of resources coming from the Tehachapi area.

There were study groups happening in Imperial and Tehachapi, but we also needed to consider the rest of the state. So, really it was a statewide focus. We didn't consider the outside WECC regions. And those were done for a reason, because we didn't want to, you know, outreach our scope. And have some results to build from. And looking at 2020 33 percent accelerated goals.

In terms of pulling together both the transmission modeling of the electrical infrastructure necessary to accommodate significant renewables, and to look at the operational reliability we needed to look at all the timeframes that, from a planner or a utility dispatcher need to consider.

Planning happens on year intervals, years. And when you consider now climate change issues, they're looking at decades. So somehow we needed to connect the data that's set up in those annual or decades datasets into something that could provide insight to a dispatcher who has to deal with them on a five- to ten-minute basis.

So the approach really was not just economics. We did look at economic metrics as a way to kind of say, well, what technologies could be viable in order for us to reach 2020 and have the confidence in those technologies to build out our infrastructure.

But the issue was also looking at how much could we realistically get in the ground before we hit that timeline. So we really looked at a transmission basis, providing a transmission metrics as a measure of how valid that resource, or how beneficial is that resource on the grid in both alleviating congestion for a load zone, or looking at the ability to dispatch that resource to alleviate congestion in some areas.

Some of our grid, in terms of interconnecting, if it's at a remote location, it could actually cause problems on the grid when it's on, versus helping the grid. So we wanted to identify those locations based on a transmission framework as it exists today. Then we can morph it and say, okay, were are the weaknesses now. And then add on transmission kind of -- or add on generation, lowest hanging fruit first, and then continue to stress the system until we hit 33 percent.

One of the results that came out of this based on the scenarios that we evaluated, and I think that has to be -- Snuller mentioned that, is there's so many different scenarios that you can come up with. And we need to consider that based on the assumptions that we put into the IEP.

These are the types of transmission upgrades and the cost estimates based on kind of an N-1 contingency failure. We didn't go to the extent of looking at the N acquisition or any of the other details. But this is very high order of magnitude levels, or high order estimates of the cost for new lines, as well as upgrades and facilities infrastructure to support those lines.

So that's not a small figure, 5.7 billion plus 655 million.

Now, considering those kinds of costs we did not estimate a economics, you know, for wind generation. But looking at these costs it rolls back to the utility to look at and say what can we afford. What kind of -- because it's going to be ratepayer based to accomplish some of these transmission buildouts.

So from that we provided those characteristics based on the system, based on the needs, based on expansion and the assumptions we put in for IEP.

We also looked at where should these resources be located, given their variability.

Geographic diversity. We considered their intermittency, their availability based on seasonal trends.

For regions that are undeveloped, especially for wind, we devoted considerable resources to come up with forecasts in those regions in anticipation of new renewable generation from those regions.

So we provided, in areas we don't have information on wind, we used a state of the art measure scale model to -- it's basically the model used for the program forecasting program, but we extended it out to 2020. And considered the profiles, the hourly profiles that we would need for some of the dispatch requirements. And considered the 3000 megawatts of PV, as well as 3000 megawatts in Tehachapi.

So, I'm not going to go into the details of the portfolio mixes. These are all in the reports. But essentially we were able to attain the different targets.

Now, what we also did was this 2010 X scenario, which we stressed the system to see how much more renewables could we put on the system given a 2010 infrastructure. And then that'll give us kind of guidance into looking at where else will we have to build additional transmission in order to get to a 2020 33 percent goal.

So, some of the highlights of the report include coming up with these characteristics on the system. 12,500 megawatts of wind. Now, we again, because this was an intermittency study, in places where we could accommodate more wind we stressed the system by pushing further wind, rather than saying it's a baseloaded geothermal facility.

But we made sure that the utility transmission planning models, they actually were satisfied in terms of what their contingencies and their requirements needed to be. So we did add conventional generation for stability requirements and other requirements for the case to solve.

Looking at some of the intermittency conditions we were able to look at conditions on the system where there was high load or minimum loads. We looked at forecasting with energy forecasting as a tool to provide some insight into improving the way that the system currently manages wind.

And we were able to quantify the savings or the benefits in a dollar amount for having a wind forecast versus having no wind forecast. And then looking at additional costs for regulation and load following in an incremental from a system basis, incremental, indirect costs for meeting those compliance targets, as well as planning requirement targets for operations.

What was interesting as we continued the study, or as we did our dispatch operation studies was for various conditions on the system we noticed we were trying to quantify what the characteristics were on the system. Doesn't matter if you're PG&E or SCE or SMUD or any of the other utilities, you have to manage your portfolio. And you need to understand what your generator's going to provide you.

And so what we ended up doing was looking at the Cal-ISO system as a proxy for the State of California, and saying what can the system provide us right now in terms of ramping capability.

Most of it came from our hydro resources. That's what the operators were doing. So it wasn't one side -- this side is the plant, the other side is the actual dispatch.

So you can see the difference in the way that there's variation in that just to meet load variation throughout the day, and also just in the way that the dispatcher's used to dealing with the resources.

So, by looking at that we removed the hydro out of the system and said for a year we had very very low hydro, what would you have to do. So, in these instances we played these kinds of sensitivity games, given the analysis and given the data. And showed that the system, based on these assumptions, came up with a 200 megawatts per minute capability in terms of a ramping.

We also looked at -- and this is something that's very important for resources that were expanding into areas of kind of undeveloped areas, or unknown resources. We really needed to understand the wind data, the characteristics of the generator, in order for us to accommodate it on the system. Whether it's the wind resources validating it with some information, or whether it's the power curves from the different technologies that are currently out there.

For emerging technologies in California, if we looked at low wind speed potential, that means class 3 and above, right now we're looking at the high wind speeds, which are class 5 and above. If we looked at class 3 and included that range, we would actually increase our footprint of usable wind for utility scale resources by five times. So our footprint would have increased that much if the technology of the emerging technology could capture those resources. And that's kind of the direction that the industry is going right now by looking at low wind speed resources.

Another issue that impacts resource adequacy is exactly this issue of seasonality and geographic diversity. So, just because you have a baseload resource doesn't mean that it is the best thing for your system. It really depends on your portfolio.

So you look at geothermal, during different seasons it may have a good or a bad impact on your system. Neutral meaning it doesn't help you either way. Spring and fall means that in that location it might cause you congestion if it's generating, because you're receiving a lot of hydro during runoffs, during the spring season.

In other areas, this just kind of gives us a perspective of the different types of resources that we could potentially inject into those regions to meet load.

So this essentially is a listing of some of the references that we had for workshops that vetted out the study. The only thing that's not on here, I just noticed, is the final report link. So if anybody's interested in the final report link, that document -- sorry? Oh, okay, all right. Pam has it, but the report number is 500-2007-081. And that's the final report. And there's two large appendices that will be very interesting reading, appendix A and appendix B. So just don't grab the final report, because there's two large appendices that also accompany it.

That's essentially it.

MS. DOUGHMAN: Okay, our next speaker is Dave Hawkins from the Cal-ISO.

MR. HAWKINS: First I'd like to congratulate Dr. Jaske, an excellent presentation. Resource adequacy is a very complicated subject and has a lot of ramifications, as we look at these renewables project.

And one of the big impacts, of course, is that if yo have to run a lot of local generation to support the voltages and so forth, when you get to 2:00 a.m. in the morning and the wind is blowing full out, where do you have enough room to negotiate down all the rest of the generation to accommodate that amount of wind. And that's been one of the challenges that we had as we looked at our integration of renewables study that we were doing. We published our report last November. So this over-generation was one key issue.

So if you're in the spring time, hydro's running full out, everything is full out, plus you've got local requirements you have to meet, there's not enough room for all of that. Which is why we need the plug-in hybrids to bring out some more nighttime load and other ways of doing it.

The result of the study that we did last year, like all good engineering studies, pointed out the fact that we needed more studies. And so we did a lot of work explaining in that original report, of what the impact, first of all, was on the Tehachapi transmission plans, and everything we needed to do to make those plans successful.

And then the second part of the report dealt with the operational issues, how much regulation, load following, ramping, all these kinds of things that Dora talked about.

Our particular study extended the work that we did on the IEP and went into more in-depth modeling of some of the resources, and came out a little bit higher amount of regulation that we would need.

But the net result was, and this is really critical message I think we're trying to deliver from the ISO, is we will make it work. Twenty percent renewables will work. We can make it work.

And it's not absolutely nothing, you know, just an extension of today. You really have to do a lot of things to make it happen. But it is achievable and the system will be reliable. And we can get there.

So, out of that initial work then we develop that says, okay, what are we going to do now. We published our report. What's the next steps. And we identified at least a dozen different projects that had to be done. And those now have been clustered into an overall program that we have been doing for 2008/2009.

The first part is really creating these

what we call operational tools. So we have, and Dora already mentioned, if you're going to have all this wind show up, you have to have a forecast. And if you haven't forecasted it successfully day-ahead, then you start a whole bunch of units that ultimately you're not going to need. Or then you have them sitting at the bottom. And also then you have a lot of consuming of gas and greenhouse gas production and, you know, things like that that you really don't want.

So, forecasting is absolutely critical. So we're out of the gate now this year with a major RFP, and we're doing indepth studies of three different companies that are doing wind generation forecasting, trying to improve our forecasting capability.

We've been using hour-ahead forecasting now for several years quite successfully. And we can usually nail the wind forecast within about 40, 50 megawatts of hour- to two-hours ahead.

But for day-ahead forecasting, that's been a much harder, much bigger variable. CEC has invested research and development dollars in that area. We've built better models. And now you're seeing really commercial companies coming to bear that can make that happen.

The next piece, of course, is trying to do solar forecasting. And this is an area where we are -- more research and evolvement at this point. We only have, well, 400 megawatts or so of solar in the state. And it's really old technology.

We've got all the new types of solar coming, different kinds of things. And the question's going to be how successful can we forecast those particular areas.

Second issue -- well, then, of course the other thing with that, if you want to make operating decisions and take action, you can't hide the forecast in the back room with a forecaster and expect the operators on the floor to take action. So you have to provide some type of a graphical display, some type of thing that says, heads up, here's where the system's going to go in the next 15, 20, 30 minutes. No surprises. Here's a weather front that's coming in.

If you're like Alberta, the other day Alberta actually had a tornado; I think it was going through their windfarm area. And it went from zero to full output as the tornado went through. And then it went to zero again in a very short amount of time.

You've got to be able to see these things coming. You've got to, whether you're using a Doppler radar or some other type of system, or meteorological towers, you've got to see the storm fronts coming and hitting your particular facilities.

And if you know that's coming and you can forecast it, you can set the system up to be able to have that maneuverability and so forth. So that's one of the key issues.

Second thing, of course, is identifying both market barriers, operational areas barriers, what things we have to change to accommodate getting more wind into the system, or all types of renewables, how to make that go.

Third part, which really relates to much more today is okay, now what are all these operational impacts. How are you going to make it work; how do you handle transmission constraints; how much regulation and ramping are going to add.

Now, wind and these renewables, we have a certain amount today in 2008. And we have that 20 percent in the future, which we think is going to be about the end of 2012. So although we are behind schedule, we do think it's going to get there. And we are on track. We will make it to the 20 percent.

So by the end of 2012, and it's going into 2013, the transmission system is built out. We think the renewable facilities will be built out, and we'll start to see the energy production out of these things. This is okay.

But we have things happening in 2009, 2010, 2011, and my vice president of operations looks at me and says, well, how much do I need for every thousand megawatts that comes on the system. And so we're developing numbers to show incrementally what the changes are going to be for each of the next years as we go forward.

As we look at the 33 percent type studies, we're just beginning to do more indepth work. The original work was done with Dora and the CEC on the IEP studies. We did a lot of work looking at that. But that was a fairly quick study compared to the indepth we're actually doing implementing the 20 percent.

And what we really have been counting on is the solar. So we're looking for concentrated solar, photovoltaic solar, other types of solar to come on as a really big complement to the wind. And as the wind basically dies away in the early morning hours, or the morning hours, during the morning load ramp up, we're expecting to see the solar come on and start to ramp up.

And if you put the two together then they make a good partnership. And the other question is how to put them together and make sure that we've got a good marriage of those facilities. So, that's a part of our big effort looking forward to 33 percent.

Another major piece that I'm working on is storage technology. And storage technology is finally arriving. There's basically two types. The first type, of course, you're all familiar with, which is the pump storage plants.

Pump storage has been around for a number of years. It's very successful. The operators love it. They can call up PG&E Helms Plant and say ramp up. You can either ramp up on the load side, or ramp up on generation. And it adds a wonderful flexible facility.

The question is going to be are we going to have more pump storage in the future. If so, where. And if you want to shift a lot of energy from offpeak periods to onpeak, pump storage is one good way to do it.

The other thing that's being proposed now is compressed air storage. The CEC funded a major compressed air storage work. It looks very interesting. There are basically two plants, I think, in operation in the world. One is, I think, in Kentucky. Is that right? Alabama. And the other one is, I think, in Germany.

Both of those use a salt cavern place to compress the air. I don't think we have any salt caverns in California, so we're looking at oh, gas wells and so forth, as places that we potentially could use for that.

So the question is research looks good. EPRI, Dr. Shainker says this is the right thing to do. It has an 85 percent roundtrip efficiency. Looks good on paper. We need a demonstration project. We need somewhere to build one of these, actually see how it works and get it in. And could we put in six to seven hours worth of energy into that system.

The other type of storage is the lithium ion batteries, the high-speed flywheels, the NAS batteries, flow-based batteries. Those are the basic ones. And now those are much shorter term. They can store energy for maybe 15 minutes, sometimes 30 minutes, sometimes a couple of hours.

And they also have a unique characteristic which they fast ramp. I mean they basically go from min to max in one second. And so, again when I talked to our Vice President, Jim Detmers, and I say we really need some of these. But, he says, but I, you know, I'm used to having things that I can schedule and move. And I say it looks to me like, you know, you're used to semitrailer trucks and pickup trucks, you know, and you can carry a lot of load here and there and so forth and deliver things.

But maybe with the volatility and the -- what you call it, the changes that we're going to see out of the wind generation, we need to have some sports cars that will accelerate quickly and make some fast turns. And we don't need a lot of them, but a few sports cars would be very useful.

So, what we have today is actually commercial products that are coming to market in the story side, and so the technology is coming. We don't have a market structure that fits that.

Our market structure is today based upon moving a thermal generator or hydro plant up and down to follow a regulation signal. And we're expecting to have enough energy to be there for a couple hours.

Well, if you're a flywheel, you're going to be tapped out in 15 to 20 minutes. Yet, it could really provide some real good services. So how do we provide a market structure and some changes in tariffs so that this type of thing could come on and have several hundred megawatts of it that would give us that kind of regulation flexibility that we're going to need for the future. So again, that goes into now the kinds of tariff changes, market products and so forth.

Now, you all say this may sound pie-in-the-sky. This is a kind of want-to-be and so forth. We actually have the first 2 megawatt lithium ion battery system already proposed. It's being shipped this month. And it should be interconnected to our system by late September.

So we are out of the gates already. This is really coming and it's real things. So, it can be done.

Other markets and products and things

need to be looked at, and how to make this all work better. And finally, of course, the last piece, compliments to Dennis, who's in our -- Dennis Peters, who's here from the ISO, also, who made the big effort to carry on the generator interconnection queue reform process. And ways that we can study things in clusters now, and really change the way that we can look at and do the overall transmission planning process.

So we are making changes. We are going down the path. And have actual plans, doing things to actually make this happen.

This is just my slide from this morning about issues about the first four questions. And this is the type of resource mix that we were looking at with the IEP study. As you can see, there's pretty good diversity of different types of generation. And, of course, when we're looking at the 33 percent, we're really, as Dora mentioned, we're out at the 12,000, in this case we had 828, megawatts of wind generation.

And geothermal, which is the other one we're looking for, coming on in the Imperial Valley area in southern California, is another major resource. That one has some interesting characteristics as we build it out. It does not operate the same as the Geysers for Geyserville. Apparently has much more variability. Again, there's more to be studied and learned. What are the models for all these different types, and most of those.

So, we've got some interesting plants. The question is whatever numbers you put together and publish, that's never the way the system would be perfectly built, right. So there's no -- all you can do is put together scenarios; your best guesses. You look at generator queues. And you make your guesses as to what you think the resource mix is going to look like.

So, anyway, these were the questions from this morning. Operational impacts. Really the whole issue then is how to put together the right kinds of scenarios. And then looking at what the impact is on once-through cooling and other initiatives as to what thermal generation is going to be left as we look out through 2015 to 2020.

One thing to think about, and this is probably part of the panel discussion, but let me throw it out now. Is that as we use the gas supply system, the gas-fired generation, and the wind generation and solar is going to actually displace some of this gas-fired generation, it's really going to ramp down the need for as much gas coming in.

However, if you have a stormfront goes through and you really have ramped up all of that wind generation, and then all of a sudden it's gone, we're going to have to fire off 3000 megawatts of CTs.

And so you say, well, gee, that's interesting. I hope the gas supply guys are there to handle that. So, when you start thinking about the whole thing about the whole gas supply business, we're going to really export part of the variability on the electric system over into the gas transmission system.

So the gas transmission is going to be jerked around. It's going to go up and down in terms of the gas supply. And we haven't yet begun to think about how we're going to communicate those changes over into the gas pipeline companies.

And they will see quite interesting changes, I suspect, as we look at some of these scenarios. And then the question then becomes okay, not only do we need some electric storage, but perhaps we need some gas storage in California to deal with that kind of variability.

So if we're going to suddenly fire off 3000 to 4000 megawatts of gas-fired generation to make up for some wind or some renewable resources that have tripped off or gone off, we've got some interesting issues to deal with in that area.

And environmental impacts. But, anyway, the final thing to think about is as we look at the future we need to work with the CPUC and the utilities to really put out more information about how much we're going to need in terms of quick start units, fast ramping capability, lower operating ranges to where we need to get to. What regulation is going to show up. How much energy shifting do we need to do.

And there are several proposals now for new pump storage plants that are being discussed, including potentially one in Mexico. Should we reinforce transmission in Mexico to take advantage of that? And is that where some of the liquified natural gas is going to show up?

So, we've got some interesting things to start thinking about, how we do those over a period of time.

And, of course, the major thing, not only storage and the integration of some storage technology, but how do we handle the demand response programs, the demand side programs. We have customers who say, gee, if I knew the signal that wind was ramping up I would shut down some of my local generation and/or modify my load.

So we've got a lot of things to think about. And, again, I think this goes back to the whole smart grid thing, how do we communicate this to everybody and give them the right information to make this work correctly.

The other thing is it can be done. Our goal is to make it work and to help implement state policies on where we're going with renewables. It's the right thing to do for climate change and everything else. And we're here to make it work.

MS. DOUGHMAN: Okay. Thanks to all our presenters on topic number 5. Now we're going to move on to topic number 6. Do we have Mark Bolinger on the phone? Okay.

MR. BOLINGER: Yes, I'm here.

MS. DOUGHMAN: Okay. I'm going to walk through this presentation prepared by Mark Bolinger and Ryan Wiser. And then if we have any questions, Mark Bolinger is available to help us out.

So, this presentation discusses suppressing natural gas prices, an ancillary benefit of renewable generation.

The first slide points out that natural gas prices are high and volatile. And we see here the historical trend in prices from 1990 through today. And then the NYMEX natural gas future strip actually from July 11, 2008, into 2020 and beyond.

Natural gas price forecast accuracy has been wanting, and this slide compares the actual wellhead price to various historical AEO wellhead gas price forecasts over time. So we see what the anticipated movement in natural gas prices was back in 85, 86, all the way up through we have a forecast for 2008 in blue

There are some initial implications discussed on this slide. Natural gas price forecasts should be current and reflect up-to-date gas price expectations. History shows us that basecase gas price forecasts have a good chance of being wrong by a factor of two.

Little emphasis should be placed on the basecase. Instead, a sizeable range of future natural gas prices should be used in an economic analysis of alternative resource options.

The value of hedging natural gas risk exposure and of reducing natural gas prices should be evaluated.

Renewable energy can help in both of these latter respects. Renewables provide a hedge against volatile and escalating natural gas prices in two ways. Renewable energy reduces exposure to gas price risk, because incremental renewable generation displaces gas-fired generation. Renewable generation is often fixed price, and gas-fired generation is often variable priced.

Second, renewable energy reduces natural gas prices. And this occurs because by displacing gas-fired generation incremental renewable energy reduces demand for natural gas. And consequently, it puts downward pressure on gas prices.

This presentation only covers the hedge benefit pointed out here, as related to the displacement of gas-fired generation. This benefit is not unique to renewable energy but comes from any generation source or demand savings that reduces natural gas demand.

Hedge benefit number two. Renewables reduce gas prices. And this is just a brief, sort of theoretical, perspective of how this would work. This comes from economics.

Increased renewable energy penetration displaces gas-fired generation, reducing demand for natural gas and placing downward pressure on natural gas prices.

The price reduction flows through to all consumers in the form of lower natural gas and electricity bills. The magnitude of price reduction depends on the shape of the gas supply curve. This is the big uncertainty, as to exactly where we are on the gas supply curve. Are we on the steep part, or are we on the part that's more horizontal.

The impact is expected to be larger in the short term than in the long term due to short-term supply constraints and longer term price supply adjustments. Price reduction may be greater in near term in regions with natural gas transportation constraints.

And this relates to the point that Dave Hawkins was making about the need to have gas supply to be able to ramp up a large amount of gas in a very short period of time.

What does this price reduction represent? A price reduction may not strictly lead to a net gain in social welfare. Lower prices may benefit gas consumers at the expense of producers. However, energy programs are frequently evaluated based on consumer bill impacts. The economy-wide macroeconomic costs from gas price increases may be significant.

California consumes gas, but produces little gas. So there may be a net gain to California.

So that's the end of the theory. Now let's see what the modeling showed. Review of recent modeling studies.

Many modeling studies have, at least indirectly, evaluated the impact of increased renewable energy and energy efficiency deployment on natural gas prices.

Mark Bolinger and Ryan Wiser have analyzed results from 13 studies, including six EIA studies of the impact of a national RPS, two of which modeled multiple RPS scenarios. And six UCS studies of the impact of a national RPS. Three of these studies modeled multiple RPS scenarios, and one includes aggressive energy efficiency, as well. They also included one Tellus study of the impact of a New England RPS with the focus being on Rhode Island.

All 13 of these studies used EIA's national energy modeling system. And the report prepared by Mark Bolinger and Ryan Wiser focuses on national impacts.

And this shows that as the amount of renewable generation is increased throughout the country, the amount -- there is a displacement of natural gas.

This slide shows the change in average wellhead price in 2000 dollars per MMBtu in relation to an increase in renewable generation. This slide shows that national gas bill reductions substantially offset any increase in electricity bills. The NPV of RPS impacts on natural gas and electricity bills varies according to the studies. But generally has a net impact on the combined electricity and natural gas bill that reduces the cost to the consumer.

Expressed as dollars per megawatt hour of incremental renewable energy, the national gas bill savings are substantial. The range is $7 to $20 per megawatt hour. At least this range captures most of the studies. Some studies showed a larger savings.

So, there is an implied inverse elasticity of supply which is defined as the percent change in price over the percent change in quantity. This measures the shape of a long-term supply curve.

The central tendency of 0.8 to 2.0 suggests that a 1 percent drop in nationwide gas demand causes a 0.8 percent to 2.0 percent drop in average wellhead prices over the long term.

There are other measures of inverse elasticity. And this graph shows a range from about 0.8 up to above 2.0 as the average implied inverse elasticity. It's not limited to the RPS studies, the use of this concept of inverse elasticity.

NEMS results are consistent with or even conservative relative to other models. Stanford's energy modeling forum results are shown here. Most models used in the energy modeling forum exhibit a national U.S. inverse elasticities that are consistent with those in NEMS.

More recently, the four models, besides NEMS, used in the energy modeling forum 23, the more recent study, exhibit inverse elasticities that are consistent with those in NEMS, as well.

There are additional studies here. And I'd like to emphasize the second bullet here. This is the scenarios analysis project. And Mark Bolinger and Ryan Wiser calculated that that project used, using a model from Global Energy Decisions, found long-term inverse elasticity of 5, which is larger than some of the other studies.

Achieving a 33 percent renewable energy target. What Mark Bolinger and Ryan Wiser did is they took the range of inverse elasticity and they applied it to California. This is some of the work they did in support of the Center for Resource Studies report prepared for the CPUC in 2005.

So this goes through some of the methods that they used. There was an assumption that each megawatt hour of new renewable generation offsets 0.75 megawatt hours of gas-fired generation at an average heat rate of 7500 Btu per kilowatt hour.

And there was an assumption that the California gas price reductions will be temporarily amplified relative to the national price reduction on a ratio of 3-to-1, declining to a ratio of 1-to-1 by 2020.

They used a projection of California natural gas demand and delivered gas prices for California electric generators from the 2005 IEPR. It was a projection of the incremental renewable generation above 20 percent to achieve 33 percent, and no incremental renewable energy after 2020.

So this shows the amount of energy used in their analysis, ramping, adding beyond the 20 percent by 2010 each year to get to 33 percent by 2020.

This shows the natural gas demand reduction in California under the 33 percent by 2020 scenario relative to 20 percent by 2010. It shows a percent change in California gas demand of about 8 percent in 2030.

The incremental California price suppression from 20 percent by 2010 to 33 percent by 2020 is shown on this slide. And as I mentioned earlier, it's not clear where we are on the gas supply curve. If we're at a place where it's steeper in terms of the amount of gas we get, with the increase in price, or it's more at the horizontal.

So this shows the impact using three different inverse elasticity estimates that were suggested in the earlier study of nationwide impacts.

So the resulting impacts from 33 percent compared to 20 percent renewable energy show natural gas bill savings for California. And this shows the savings from 2011 to 2020, and 2021 to 2030. Net present value in 2011 of gas bill savings on the order of a billion dollars. Depending on the inverse elasticity.

Open questions and areas for further study. We need to more comprehensively evaluate historical and empirical inverse elasticities of gas supply to help benchmark model results. Need a deeper understanding of the degree to which gas price reduction is a social benefit rather than a transfer payment from producers to consumers.

And we need to better evaluate regional price impacts of regional reduction in gas demand with more finely tuned gas models. And better understand physical changes to natural gas supply delivery and storage system to respond to 33 percent renewable energy.

Possibly reduced demand for and economic competitiveness of liquified natural gas. Possibly reduce need for new natural gas transport capability to California. Possibly increased need for gas storage and increased cycling of that storage to integrate variable and uncertain renewable energy sources, as was mentioned by Dave Hawkins.

And here we have a partial bibliography of some of the sources used in this study.

Before I go on why don't I pause here to see if there are any questions from Mark Bolinger or if Mark wanted to add anything. I don't see any questions. Mark, did you want to add anything?

MR. BOLINGER: No, I don't think so, thank you, Pam.

MS. DOUGHMAN: Okay. So, the last topic before we go on to our panel discussion, is a brief overview of the environmental concerns and mitigation.

There have been a number of reports and activities prepared to address some of the environmental concerns related to different resources, different renewable resources.

In November 2006 a roadmap for the development of biomass in California was prepared through a PIER collaborative effort. In October 2007 the Energy Commission published California Guidelines for Reducing Impacts to Birds and Bats from Wind Energy Development.

Also, there is a memorandum of understanding between the U.S. Department of the Interior, the Bureau of Land Management, California Desert District, and the California Energy Commission Staff concerning joint environmental review for solar-thermal power plant projects. And the Energy Commission has a proceeding that's just getting started addressing that issue.

Also the Geothermal Energy Association has prepared a Guide to Geothermal Energy and the Environment. And there is an earlier annotated bibliography that came out in 2004 that was put together by the U.S. Department of Energy discussing geothermal literature regarding environmental issues.

Okay, so now we're moving to our second

panel of the day, and to get us going we are going to have a summary of the scenario analysis for the electricity sector, discussing response to questions for topics 5 through 7.

DR. JASKE: So, having explained what resource adequacy is all about and how it might apply at a sort of conceptual level to renewables, what did the scenario project, itself, accomplish in this regard? So, out of the many subsidiary questions the overall question 5, that's what I'll try to explain here.

So, just to remind you, we're supposed to be addressing, in the California context, all the months. So the first sort of limitation that we encountered is that we were only really able to address the peak month for each control area.

We were focusing on that peak month. We were looking for the nameplate and/or the derated capacity, what technology was in question. So we were tackling that specific element of resource adequacy. But because on a westwide basis we only had one year of wind data, this NREL dataset that's been floating around since about 2002, we were not able to do a three-year rolling average, but rather only an average across a single year.

So another limitation.

As I explained before, we were using a production cost model with sort of transmission bubble level of geographic disaggregation, so all of the minutiae of local resource adequacy, you know, would have to be -- had to be sacrificed.

So, for example, in the 10 LCR load pocket presentation or construct for California, and who actually knows what local resource adequacy is in other parts of WECC, we were not able to identify those vesticular regions. For example, Ventura Big Creek; that was all lumped together into a Southern California Edison bubble.

But, nonetheless, with those limitations we generally were backing out, you know, any generic additions as we added the preferred resources. We did a resource adequacy check to see whether we were meeting the single annual peak load times the 1.15 to deal with the planning margin. And then where we were short we added combustion turbines.

So, you know, in sort of a simplified fashion trying to follow the California resource adequacy construct throughout the entire western interconnection.

So, one element of that step, of course, is understanding the derate factor for the renewable technologies, so this gives you a sense of what those are. Wind being derated the most, and California wind being derated moreso than the rest of the west. Not too different on the low side, but there's quite a bit of what one might call better wind out there in other parts of the west that flows quite continuously.

Central solar has a derate, but not nearly as large. And actually, because California is one of the better locations, it probably has a better overall factor than other places in the west.

And rooftop PV also has a significant derate because we're talking about, you know, peaks at 4:00 in the afternoon, which is well past the peak performance of residential and commercial rooftop, which almost or very infrequently have any kind of a proper tilting mechanism. And so they're all generally were portrayed as fixed systems. So those two phenomenon lead to a pretty significant derate for PV.

So, here's how the numbers actually worked out in the case of 4a. Showing three technologies that suffer this derate that I was just explaining, and then demand response in steam turbines will be part of the solution.

So in the nameplate capacity column, you'll see what those resources were in case 4a. Next column over to the right is their derated capacity by applying those general factors, as I explained. And the bottom of that column you can sort of see how 8500 compares to 19,600, far short.

The next column over is the implied deficit in capacity, simply the subtraction between the previous two columns. So there's about 11,000 megawatts of capacity deficit reflected by this NQC approach.

So, how did we solve that? Well, it turns out that we have the old steam turbines that are generating very little energy, but are still there for capacity. And we have somewhere around a third of the old capacity still left in year 2020. And I guess I don't say anywhere on this slide that this is for year 2020.

And then we have a bunch of demand response, which also is a capacity resource. And so in July of 2020 the way the analysis went, it just so happens that we have just about the right amount of peaking resources to offset the capacity deficit. And this is a relatively big capacity deficit, because there's a very strong emphasis on wind. If we had had, you know, less wind and more central, then we wouldn't have had as big an issue. And Dave explained that well.

So, even though we're not -- well, not even though -- we're not fully implementing all of the resource adequacy requirements. We're focusing on July. And an important phenomenon there is that the DR solution, you know, is relevant in the summer months. Its capability may differ somewhat from one summer month to another summer month, but they're more similar than those summer months are to all the other months of the year. So the DR option that showed how wind deficit largely wind deficits could be overcome is not going to work in other months.

And if you remember my earlier presentation about how wind NQC rolls off, there's actually a bigger wind deficit in the late fall and winter months. As I said before, we weren't examining the local resource adequacy part at all, and so this is only looking at sort of from a system perspective.

As I mentioned before, all of this is part of what the PUC is going to be looking at, or in phase two of the current resource adequacy proceeding. And a facet that may also evolve over the next year or two is if the PUC -- well, depending on how the PUC, let's put it that way, moves forward in resolving the central capacity market element of resource adequacy, or whether it relies on a bilateral market formulation, there's general consensus that the time horizon of resource adequacy analysis and possibly resource adequacy commitment, moving that forward, moving that out there from one year ahead to four years ahead, five years ahead, six years ahead, something of that sort.

And so there will be much more emphasis on the issues likely we're tackling in this project without a whole lot of guidance, how to make these projections that far forward. Because you introduce much more uncertainty as you do that. And what is the mix of renewable resources; where will they be located; can the transmission system, itself, evolve in some manner to ameliorate some of the local requirements. Those are topics that if we have a four-, five-, six-year-ahead forward time horizon would become much more important.

Okay, shift gears completely into the natural gas area. Mark Bolinger's slides that Pam went through, talk about the gas impacts of renewables. And that was a topic addressed quite explicitly in the scenarios project. In fact, it was addressed because the PUC had funded CRS to do a study.

Since we knew we were examining high penetrations of the preferred resources, we deliberately set about to do a gas price impact analysis. It wasn't just a fallout from the scenario project, per se. It was done expressly to try to look at this phenomenon.

So, as was mentioned, we were using Global Energy production cost model, and their consulting team, to do much of the analytic work on this project. They have a separate unit that does long-run gas analysis. And so we hired them for this project.

We chose to look at case 5b, which is more than just California. This would be the combination case across the whole west of both energy efficiency and renewables and rooftop. So this is the case that's going to have the largest likely reduction in power plant natural gas usage, and therefore the one that would lead to the largest natural gas price reduction, to the extent there is one.

Now, in the analysis that we funded Global to do, we were not looking outside of the WECC footprint. So we did this analysis of the westwide western interconnection level, assumed everything else for the country, for the North American gas market was the same.

This is a portrayal of the WECC-wide natural gas usage in the various cases. The orange one at the top is the case 1, and then the next one down is case 1b that we tend to think of as the reference case, because it's the approximate implementation of 20 percent RPS and efficiency programs, you know, sort of as mandated circa 2006.

The other three lines are the various preferred resource scenarios. And I'm showing these intermediate ones that are case 3b and case 4b because they were used in the sort of step-by-step analysis that Global Energy did.

And at the very bottom with the triangles is the case 5b, which has, on a westwide basis, both efficiency and renewables. And so, as expected, it's the lowest projection. It actually has a reduction in gas usage for power generation over time. And so the analysis, from the normal scenario project, quantified this, and this became the input into the Global team.

I guess I said all these things. So, what was the outcome. We found, as Mark Bolinger's slides show, a fairly substantial impact in this analysis. We actually became concerned that the impact was so large. And so the staff contracted with Altos, who's the provider of the NARG model that Energy Commission Staff have used for many years to do gas planning, to do an independent estimate.

And I'm going to show the slides from the August 16, 2007 workshop to sort of contrast the two different outcomes that they got. And then try to say a little bit about what we understand is the reason for the difference.

So, here's just a few slides prepared by Ann Donnelly and other folks with the Global Energy Decisions gas unit, now the Vintex gas unit.

What we're looking at here in this slide is a set of price projections from 2009 to 2020. These are Henry Hub, so that's sort of intended to be the focal point of gas price projections for the whole North American continent.

The ones to pay attention to are the ones down near the bottom. There is also, up at the very top of this chart, a scarcity pricing projection, but it's there to sort of give reference, in the case of this workshop presentation from last year, how all these others compare.

The real focal point is the next line down, which on the screen and on tv is blue. And then there's a series of three other lines clustered much closer together that are orange and green. Those are the ones that would be the difference between these that we pay attention to.

So this slide takes away some of that other clutter and I can explain sort of the step-by-step results.

The top line is the original starting point projection for the case 5b. As one feeds back the gas for power generation consequences of the case 5b back into the gas price projection modeling, they did it step-by-step, so they did the 3b step first. And so there is a red line, for those who are able to see color.

Then, as one goes to the 5b case, here in the label called 5b LDF, that means that they moved from the 3b case to the 5b case. So they added the renewables. So the renewable consequence on a statewide basis, on a westwide basis, is to go from the red line with squares to the orange line with triangles.

Now, that's not the end of the story, because that price reduction would have assumed that there were no physical or no long-term responses from gas producers. And all of that reduction from the red squares to the orange triangles is effectively the short-term response of producers, having less gas demand, therefore a lower market clearing price.

When you take into account that producers have long-run capital investments, they have wells that are being depleted with more drilling and other things that they wouldn't do to the same extent if they now knew that we were in a scenario where there was going to be less gas demand over time, they wouldn't do all of that expenditure in the first place.

And so, in effect, the gray line that has little cross-hatches on it, is the final result that Global Energy people came up with.

And so comparing the blue line at the top and the gray line, which is actually the second one down, although the last in the sequence of analysis, you get somewhere in the range of 50 cents to $1 per million Btu as the consequence. And as Mark Bolinger's presentation indicated, that's a pretty high number.

So, having seen these results, we, as I said, the Energy Commission Staff contracted with Altos to run their version of NARG within the suite of models that Altos runs. And which is broader than the suite of models that the staff licenses, so we had to have Altos do it as opposed to Commission Staff.

And here are their results. Again, Henry Hub, again, going out, in this case, only to 2018 with the particular dataset they have. There's a little two-years difference, but the message is the same.

And you can see pairs of columns for

each year, the preliminary and the alternative case 5b. So, instead of having two sets of lines, they have pairs of bars.

And you can also see a different phenomenon here. There's some kind of cycling going on. 2009 is up; 2010 is down; 2011 is back up more; 2012 is back down. And it's rippling sort of every other year.

As I understand it, that's a function of how Altos is introducing new resources into the system, particularly lumpy ones like LNG. And they're getting sort of market clearing prices that change actually quite a bit, on the order of 10 percent, from one year to the next. But if you sort of drew a line, you know, through the middle of all that, you'd have a relatively smooth upward trajectory.

What they found when comparing the blue and red columns, or namely the original basecase and the red, which is the case 5b, is much more in the range of 10 cent to 25 cent per million Btu. So that's somewhere between a fifth and a quarter of the size of impact as the Global Energy folks did.

And as I understand the sort of back-and-forth preceding the workshop between the two teams and the Commission Staff, and at the workshop, really the result is heavily affected by the scale of the analysis.

As I said before, when we had Global do their work we didn't change the assumptions about what was going on in the electricity sector outside of WECC. And in this particular analysis neither did Altos.

However, the basecase for Altos is not the same as the basecase for Global. The basecase for Altos is a future world in which CO_2 mitigation is already happening. So there is already, in their basecase, a significant shift from coal to natural gas. And so the scale of natural gas usage in the Altos analysis is substantially higher on a North American market basis; therefore prices are trending upward at a higher rate, although when you compare the two charts, they're in about the same zone.

And then the incremental effect of just a WECC-wide reduction in power generation gas demand isn't nearly as large, because the base power generation demand is so much larger in the Altos analysis, the proportional effect of the renewable strategy just is less. And therefore its influence on the market is less.

That is the fundamental difference between the two analyses when you get right down to it.

It reveals, again, the consequence of the integration of the gas and electricity sectors together, the sort of convergence phenomenon that people have talked about. And now the overlay of global climate change, mitigation strategies and what that will mean in terms of the rest of North America pursuing these same strategies. And teasing out consequences of a region, you know, becomes very much more difficult.

So, the upshot of these competing analyses was in the 2007 IEPR in recognition of this phenomenon, but no willingness to endorse any particular conclusion or results because of the uncertainty here and how to address sort of yet larger and larger geographic dimensions that are important to trying to understand consequences of California or westwide policies.

So, that's how we attempted to deal with the natural gas impacts in the scenario project.

MS. DOUGHMAN: Okay. Why don't we take

a 15-minute break, and then come back and finish up the panel and public comment.

So, we'll see you back at 3:20.

(Brief recess.)

MS. DOUGHMAN: We have two remaining tasks for the day. The first is to have our panelists, the remaining panelists, discuss topics 5 through 7. And then we'll have public comments on topics 5 through 7. And then we have some general questions, and then we'll adjourn.

So, let me take my seat at the table.

(Pause.)

MS. DOUGHMAN: So why don't we -- Dr. Jaske, go ahead.

DR. JASKE: I have a question -- more a question than a comment -- on Dave Hawkins' presentation. And it has to do with this issue of resources in load pockets versus the present location of renewables outside of load pockets.

So, you know, all those technologies for storage and other things seem like they're capable, at least potentially, of overcoming intermittency and production profiles that sort of don't match load.

But how do we -- do you have any

observations about dealing with this physical location and the whole contingency planning that the LCR is supposed to be able to overcome?

MR. HAWKINS: That's a good question. The pump storage, of course, is very locationally dependent. And compressed air storage, again, will be fairly -- you know, you got to go where the gas well is, or whatever.

But the other type of storage is basically very modular. You could put it in a warehouse in San Francisco or Oakland, or down in Los Angeles or whatever, anyplace that you could get a interconnection back into the transmission piece.

So you could put it in existing generating station. In fact, the 2 megawatt unit that we've got coming on this fall is literally going to be located at an existing generating plant.

And the advantage is, of course, you've already got a transmission interconnection, and you've already got a transformer sitting there. So now, you know, if potentially you've shut down a unit at that plant, it's decommissioned, you basically have spare capacity.

So you could think about dropping in a 20, 30 megawatts worth of storage technology in these locations, and it's a pretty easy interconnection thing to do.

So, the advantage of a lot of this storage is very mobile. And, in fact, you can -- AEP has even proposed putting it into as mobile units in substations now so that they will actually move it from substation to substation, and basically defer upgrades to that transmission substation or distribution station for a year or two years or three years. And then move it on to another location.

So, it has some great advantages from that perspective. So although at this time it's still pretty costly, so we're hoping to see the prices come down. But it does have some interesting capabilities.

MS. DOUGHMAN: How about if we have each of the panelists just go through your thoughts on questions 5 through 7, and then --

MR. HAWKINS: Okay, well, let me make a first comment, if I could, --

MS. DOUGHMAN: Okay.

MR. HAWKINS: -- back on resource

adequacy. And the big issue is from a operator's perspective, which of course, is the operator on the floor will always remember that at 4:15 in the afternoon for 30 seconds the load on the system was 49,200 megawatts, and the wind that showed up was only 50 megawatts. And that number will forever stick in his mind.

And you way, but, you know, we have to look at wind and other resources over a bigger period of time. And, of course, then, you know, he says, well, it never shows up and so forth on peak.

So what we've tried to do is to bring a more balanced picture to the table. And so instead of just thinking about that number, basically what we see typically is somewhere between 5 percent to 10 percent of whatever the nameplate ratings is on wind or so forth. We see numbers like that basically going around across the peak afternoon.

So, originally we had proposed what we called a 3-3-3 plan. And so we were looking at three years, three years worth of data. And for each month you would pick out the three days that were the peak load of that month. And then for those three days you'd pick out the three hours where the peak actually occurs.

And the peak typically occurs not between noon and 6:00, which it actually does, but it actually occurs usually between 2:00 and 5:00, at least in the summer. And it varies a little bit from area to area.

Then, of course, if you're looking at December, the peak load in December actually occurs between 5:00 and 7:00 in the evening. And if you're there in the operating center at about 5:15 when the sun goes down, all the street lights turn on and all the Christmas tree lights turn on, you see the load go straight up about 1000 megawatts in about 15 minutes.

So, we see some interesting variability at different times of the year. And so, just incredible changes.

So, then the question comes, okay, what is reasonable. So, we had proposed that as a way of trying to say, well, how much wind generation do you get during those three years, during those three days, during those three hours.

And basically it's, you know, it's an economic study, too, as well as a reliability study. Because you really don't want to penalize wind or renewables. You really want to give them a fair shake and a fair compensation at the table.

And so, although the operators love the 3-3-3 plan, it doesn't politically sell. And so the number is probably a little bit larger. So we're still in the debates as to what is a reasonable formula for looking at how much to account for resource adequacy from those renewables.

And, you know, -- and, again, the thinking is you really have to look at the characteristics of how California climate works. And if you look at a month like July this year, the weather's been pretty beautiful. We had a few really hot days, and then the rest of the month has been quite reasonable.

So, the question is, if you pick out the three days or five days or ten-day period or whatever, is that more realistic of the way the weather works and the renewables work, and how the two pieces come together.

So, that's probably a long answer to how you think about resource adequacy, but it's a key -- a keen issue, and it's a financial issue, as well as reliability issue. And you really have to have an answer that's fair to all parties.

Impact on natural gas, I think I've already commented on that. Could demand side management strategies be effective in reducing the impact. Absolutely.

We are absolutely convinced that there's tremendous more things to be done to link up with demand side and thermal storage and other ways, if we have the right kinds of programs. We would encourage much more thermal storage.

We'd like to see compressor loads for chillers in large buildings that have variable capability, variable load capability. Today they basically are constant. And basically they change the temperature in the building by turning on the heaters. And you say, that's not very efficient.

And so we actually have customers who are willing to spend money to retrofit their buildings, retrofit their campuses. The university campuses are a good example. They have lots of low-cost, very bright labor. And they have professors who are very interested in trying to make this happen. So we have great examples.

Plus the state, itself, is a big

landlord. It owns a lot of buildings. So the state could really take a leadership role in trying to do this with its own state buildings.

So there's a ways that we could send signals from the ISO that says, here's what the wind is doing. And would load be interested in ramping up, ramping down, bidding their changes into the market. And modifying their output.

So, I really am convinced that we could do a lot more to modify load demand to foot the variability of some of that.

Natural gas, we have not done major natural gas pricing studies. The only thing that occurs to me was in a speech that I saw earlier this year at the National Association of Regulatory people, and from a chap whose name escapes me at the moment, who really showed that the price projections that Washington puts out on natural gas prices, they've never gotten it right yet. And so their price things are way under on your schedule. It was EIA.

And so that, you know, the same as we've had some unexpected escalation of gasoline prices over the last couple of years, or the last year, I'm still thinking that natural gas pricing is potentially subject to a similar type volatility.

I look at the modeling studies and, you know, they're extremely detailed and convincing. I just still think there's some wild cards out there as to what's going to happen with some of the natural gas price. Demand is certainly going to go down, but I think we still have some big variables.

And environmental concerns, I guess I go in the Al Gore Camp. I think renewables are extremely important to do; it's the right thing to do for the environment. So, I'm onboard.

MS. DOUGHMAN: Okay. Dora, do you want to go next, or --

DR. NAKAFUJI: Okay. Well, I think just based on the assessments that have been done so far, regarding operational changes, this is a transformation stage, as we mentioned before, adopting these new technologies.

And I think there is, the more I'm talking with the industries and working with them and looking at this resilient transformation, you see the struggle in two different camps.

One is the transmission side that does long-term transmission planning, that deals with the resource adequacy. Then you've got the operational side that has to deal with the dispatch.

The requirements are driven from two different sides, too. Resource adequacy is a CPUC requirement for servicing load, making sure that we all have electricity in those much-needed hours of peak.

But on the operating reserve side, that 7 percent is really to make sure that we have reliability across the grid, because we're all interconnected to the rest of WECC.

So those things are sometimes not necessarily connected, especially when we're doing planning on these resources. The dispatch side doesn't necessarily see that same type of planning approach. And so when they dispatch they follow a very different approach.

And so trying to bring those to earlier, to the table for discussion, I think, helps in understanding how to plan forward in terms of addressing these renewable issues.

Seasonality is a big thing. You know, we don't take an average of the year. We have to look at the seasonal trends for these resources, especially for wind.

We've also found on solar, and I didn't mention it, but in the IEP there was a study on the solar resources, looking at their ability. Because we anticipated PV coming online, 3000 megawatts additional CSP that may or may not have firming, natural gas firming that we have right now with the SEGS facilities.

But the variations that solar forecasting really needs additional research work as far as monitoring the sites that are actually generating, similar to what wind -- what we're doing requiring from the wind resources are too. To couple that information into some of these planning models.

An approach was suggested in the IEP using California Public Utilities self-generation program data. It's actually one of the most complete data that we have, and we're very fortunate to have that information available to use for the state.

As far as characteristics, that's another operational issue. I think the characteristics are very important, that if we start putting too much dollar amounts to these things, because, as everybody mentioned, forecasting the cost is relative. I mean it'll change when these price signals change.

The characteristics of the system don't move as quickly. You have to change the infrastructure to a certain degree in order to see these characteristics change. So, using that as a metrics, to then, you know, take that number and have the various utility service areas with the regional areas, put a number to it based on their portfolio, might facilitate some of this transformation needs.

I think demand side management strategies, yes, those things are essential as part of the portfolio. Because the distribution side is as much connected to the transmission side, so they have to be hand-in-hand and be coordinated.

But the distributed generation strategies and the technologies, I think, also have to be very well coordinated with the utilities. As Dave mentioned, the control aspect is very important because if you're taking away customer load, you're really not helping, you know.

As far as potential impacts on natural gas, this backing up with natural gas, it's kind of a shuffling game, again. You know, you're replacing wind with natural gas, and in the long run are we really making that much of an impact on our environmental goals.

The environmental concerns for large-scale renewable facilities, this question about should additional environmental criteria be added to the portfolio standard eligibility, that, I think, is going to raise a lot of questions.

Considering we're trying to refine the process and we've got so many different jurisdictions already with different guidelines, different approaches, different perspectives. And I'm not certain if another requirement is really going to help the jurisdictions with their uncertainty or their lack of data in terms of monitoring for some of these species in the large expansion areas.

So the decision data, however, is necessary. So research that can help them make those decisions might be more beneficial to these jurisdictions.

And then, so permitting and siting, I

think, trying to simplify that is still -- it addresses some of the issues that we mentioned earlier.

As far as what other studies are underway, I think some of this will be discussed on the 23rd on transmission studies. But there are a lot of regional studies that are being pursued by -- supported through the Department of Energy; National Renewable Energy Lab is supporting the west and also the east in various laboratories. They're also supporting that in terms of validating the data, coming up with basecase renewable datasets.

And then there's also a regional integration of renewables project here funded through the Commission. That's kind of an extension of the intermittency analysis project looking at northern California, least -- transmission development. And that is also a utility's planning perspective where they've come together as a group to kind of develop some basis for looking at long-term planning strategies and some common transmission that's necessary to build out portfolios of generation, whether it be renewables or other critical support infrastructure in order to bring in exports. And also, as well as to accommodate renewables.

So, I think there are many of these, and there's also the Western Governors study that's currently underway. So there's a lot of data that's going to be forthcoming. And there's a good amount of information here in California to continue to support those efforts.

MS. DOUGHMAN: Okay, Snuller.

MR. PRICE: Thank you. I'd like to provide maybe a slightly different perspective. We've talked a lot about reliability and how to work on and evaluate keeping our system reliable under a 33 percent RPS. I think that's super-important.

And as we continue, or we ramp up to work on and support the CPUC 33 percent staff analysis for RPS, we're going to want to incorporate all of that sort of information and work on the reliability pieces.

But there's also some other challenges that we're thinking about in terms of planning and how does the 33 percent study that we're supporting going to look at it.

And the first sort of words that come to mind to sort of characterize it overall is it's really a paradigm change. It's really a big shift from the long-term planning processes and resource planning processes that we've done in the past.

What we've done in the past is to forecast loads, account for energy efficiency, and then build what we need to keep the system up and reliable. If I look at the 33 percent RPS and just the quantity of energy that we're going to need to add to the system to hit 33 percent by 2020, what I find out is that there's actually not enough room for all of the conventional resources that we have already, okay.

So, it's not a matter of just adding more to get load. It's adding more and actually displacing something on the order of 11 percent of the conventional resources that we use in the state by 2020 with renewables. So, it's a very different kind of planning perspective.

I think the other things, there's a number of other things that are just really a challenge that are adding on top of that. One is the once-through cooling issue. I think there's something like 28,000 megawatts, some huge amount of generation in the state that uses once-through cooling that we're on the hope to phase out over some uncertain period.

And there's a lot of question marks about even if we retrofit and can retrofit, we're going to have to have plants offline, and we're going to have to manage that whole process.

There's another who challenge, as well, under retirement or repowering of older generation facilities in the state. And now I think more than ever the sort of local communities and the environmental justice issues around retirement and repowering of existing plants is going to be tremendous. There's going to be a lot of focus on that. And so there's a lot of uncertainty about what's going to happen with our existing plants.

The other thing that I've noticed is that the CPUC has just released a sort of a proposed decision on energy efficiency goals. And the CEC has its own process on establishing energy efficiency goals with the public utilities in the state. And the goals are unprecedented high, okay. They're sort of in an uncharted territory.

Not that we can't do them, not that we won't, but in terms of planning we're really counting on achieving an amount of energy efficiency that's well beyond anything that at least I know anybody's ever been able to accomplish.

So, the last thing that's, I think, a big challenge that we've seen with the new transmission line sitings is just how difficult it is to get a new transmission line up.

I don't feel like it's a matter of money so much, although money is obviously a large part of it, it's just can you get the sites. It's you're going to get through the environmental process to be able to establish a new transmission line.

So, there's probably some more, too. But there's a number of challenges that we have in terms of planning of renewables, reliability and sort of across the board.

In terms of the other questions, I think I addressed most of them. The natural gas demand and supply, that's something I'm going to have to think about a little bit more, but I'm just initially a little hesitant to count on a lot of natural gas price reductions. From a public policy perspective, one of the -- the big issue that's driving 33 percent RPS is greenhouse gas reductions.

And it seems like we have a lot of policies to reduce greenhouse gases, one of which is RPS. But there are others. In particular, moving away from coal generation. So we have SB-1368, which basically limits new coal development funded by California entities.

We've got a lot of pressure, political and environmental pressure, not to build new coal. The Texas merger comes to mind of -- was it last year -- where a number, I think 15 or something like that, coal plants were basically put on hold. Seems like every day there's a new coal plant somewhere that can't be built in states that you would expect could build a new coal plant.

So, while we can displace natural gas with renewables, I'm worried that we'll have even more demand for natural gas as we move away from coal supply. And it's a regional market.

So, from a perspective of environmental policy bringing down natural gas prices, I'm not sure sort of where that falls out.

I think that's the summary.

MS. DOUGHMAN: Okay. Jaclyn.

MS. MARKS: Well, I'm strategically

placed after Snu because I absolutely agree with him that -- this was planned -- that this new paradigm of renewables coming online and actually decreasing the amounts of conventional and fossil is going to require a whole new way of planning. And that is really why we, at the CPUC, are taking this 33 percent staff analysis and taking into account as part of the long-term procurement plan proceeding.

So that we're not stuck with stranded costs in the future. That today we are aware, as far as we can be, the policy in the future and the uncertainties and know where we need to go based on what we know today.

I would also just like to emphasize that I'm encouraged that the CA-ISO will be studying the operational impacts of 20 percent, and is working on 33 percent renewables to be later this year. That's great. We need that type of analysis. And it's really a key input into what the PUC Staff analysis will do, and also the IEPR analysis.

Just two specific points about that analysis. What we're really looking for is some type of quantity of the ramp and regulation needed to integrate 33 percent renewables. Because it is this new paradigm; it's not, you know, conventional natural gas-fired amounts, it's flexible fossil, it's peaker plants.

Also the cost to integrate these plans. But I know that's a tall order by the end of the year when we would hope to get that type of information. So, at least if we can get some type of perspective of the quantity of ramp and regulation needed, we can work out in turn a methodology through Snuller Price and our E3 consultants to get a handle of the quantity of ramp and regulation needed and cost estimates.

So, we look forward to working together with the Cal-ISO on that.

And I'd also like to mention that at the CPUC we have a wealth of information on the RPS procurement process on, you know, the number of contracts that have been signed, which ones are new, and we're happy to work with you and provide you with this data for your analysis. And, of course, the same goes for IEPR.

And just one last comment. I'd like to respond to Jan, who, unfortunately isn't here, but I'd like to make a point on the feed-in tariffs.

First of all that when she spoke about the QF program she spoke about it like it was in the past. But we actually still have the QF program in place today.

Ad renewable projects are still eligible to participate in that program. So we do have a feed-in tariff for renewable projects.

And second, we have a least-cost/best-fit methodology for choosing renewables. The investor-owned utilities implements that methodology when they rank and choose which specific projects that came through the competitive solicitation to negotiate with.

And this methodology, this best fit takes into account when projects come online, any maybe innovative technology, whatever the unique attribute is that makes that project more valuable is considered when the investor-owned utilities are ranking bids from the solicitation. So we are already doing that.

Perhaps feed-in tariffs could, you know, play a role in increasing the amount of renewables. And for those of you who are not aware, the PUC is currently looking at a feed-in tariff for projects, renewable projects that are

20 megawatts and smaller.

And that's it for me.

MS. DOUGHMAN: Okay. Any members of the panel want to respond, or just ask questions of other members?

DR. JASKE: Yeah, let me just sort of try to maybe connect the dots, to use a metaphor that Mr. Yakout likes, or Monsour likes to use a lot. And that is pursuing renewables in the face of these many issues, OTC, resource adequacy in general, local resource adequacy, climate change, you know, really means a whole host of fine detail about what resource fits in what little slot.

And, you know, we used to have a process with integrated utilities where they could undertake those in analytic studies. And once they came to a conclusion, make a decision and generally get it through their regulatory entity.

So much harder to do those things in the current environment. Not everyone has all the right information. There's 18 different incentives from Sunday that guide various players in the industry.

So, some ways of perhaps not a horribly difficult problem, you know, from an engineering analysis perspective, becomes so much more difficult with this market overlay. Of course, we're not going to solve that problem. But we need to recognize that there's just a whole slug of conditionality about once you decide what seems to make sense, from a planning perspective, how could it actually happen in the real world.

MS. DOUGHMAN: Any more comments from the panelists?

MR. HAWKINS: Good comments. I'd just echo the fact that, you know, good planning is essential to make this work. And it's not going to happen by accident. It takes really dedication and resources and people and policies and plans to really make it work.

So, we're on the right track with these kinds of workshops.

DR. NAKAFUJI: Also, just Jan mentioned that we need to start today. There's a lot of work that we can do today, given these uncertainties, to start filling in the gaps for information, especially where there are seams, meaning like the transmission and the operation, the utility industry and the market environment.

You know, those are the seams where a

lot of these issues are going to fall through as we have this paradigm shift, or this transformation into this new utilities-managed resource kind of perspective.

And we need to be cognizant of those, because otherwise it's going to be pitched over and you assume it's taken care of, and it's going, in the long run, cost us more to come back and band-aid it or, you know, provide the infrastructure or the security to make it sustainable.

The other thing, too, is I forgot to mention this earlier related to the environmental side. Should there be focus on repowering existing wind facilities? This is an issue that I think is very germane to California, given that a lot of the facilities we have are very old, the technologies, the turbines that we have. Not that we don't have new technology, but this is a problem that I think is more unique to our state than any of the other states.

And so if we don't repower our existing facilities or facilitate that repowering, we're really -- a lot of those resources devolve in the prime locations. If we don't take advantage of that, we're going to really lose out on optimizing resources that have transmission capacity that's close to load. In the case of the Altamont. And, you know, we're not really optimizing the resources for those needs.

MS. DOUGHMAN: Okay, anything more from the panel? No?

Okay, so I have some blue cards. And as we go, if you'd like to join the stack of blue cards, just why don't you, Kevin and Mike, raise your hands. Just raise your hand and Mike or Kevin will come to you.

So, first I'll go through the blue cards that I have here. Then we'll go to the phones to see if there are any questions or comments. And then we'll go from there.

Okay, the first blue card I have is Bruce Baccei.

MR. BACCEI: Baccei.

MS. DOUGHMAN: Baccei. Go ahead.

MR. BACCEI: Bruce Baccei; I'm with SMUD. Let's see, on the pricing and all that, on the demand side I think pricing is another thing that we should look at. That that will make a big difference. I know we're looking at different rate structures and so on.

But the main thing I want to mention, we have a new contract with the CEC that's just about -- we've been working on it for three years. And we think it's finally going to be born in the next few months. But it's part of the ZENH program.

And one of the things that I'm recommending to get closer to zero is to not just look at energy efficiency and PV, which it has been in the past, but the other ingredient I want to bring to it is passive solar.

And I'm talking about passive solar heating and cooling. And that's not anything that I've heard mentioned here.

Before I worked -- I've been with SMUD just ten weeks. And before, for the last five years I've been managing one of the Building America teams, called Building Industry Research Alliance, BIRA, managed by ConSol in Stockton.

And in any of these areas you need to work with early adopters to be, you know, cutting edge. And we worked, had the great fortune for John Suppes with Clarum Homes to come forward. He built a big development down in Watsonville, 257 houses. And with that success he wanted to look at how to build super-efficient homes in the super-hot desert.

So he came to us wanting to build four prototypes down in Barrego Springs. Two of those houses were built with a concrete sandwich wall system. And that's not going to catch on and go all over the place. But just to kind of show you what you can do.

So it was four inches of concrete, four inches of styrofoam, two inches of concrete as you go from inside to outside. And it doesn't cool off in Barrego Springs, you know. But there is a diurnal swing, so it is cooler at night.

And so I asked that we do a -- we had NREL run this experiment for us. We cooled the houses from 10:30 at night until noon. And then shut the air conditioners off. And we did this in a couple of side-by-side houses.

In these houses that had concrete slab floors and these concrete walls, the temperature changed 4 degrees between noon and 10:30 at night, and 105 degrees outside.

Now, that's kind of an extreme thing, but I can tell you about my mother's house. My mother lives over in Woodland, just 20 miles west of Davis. And forever, I mean this is nothing new, this is what my mom and dad have been doing for years, I mean it's not that well built or any of that kind of stuff.

But we are blessed by this diurnal swing in temperature in this valley most of the time. And so she opens it up and cools it off at night, maybe even runs a whole-house fan. And then if it gets really hot she runs an evaporative air conditioner, single stage, old time swamp cooler. And that's all she has used for all these years. Those kinds of things can be enormously helpful.

And with the peak pricing there can be an incentive. We can educate people about cooling. In addition to charging the SUVs at night, run your air conditioner at night. That's fine. And then keep the house closed up.

The other thing is just simple shading. If we just shaded west glass most of our peak would go away.

PV orientation. On another Building America project right here in Rancho Cordova, SMUD provided us data. They monitored their two projects, roughly 200 houses; 95 houses, 98 houses side-by-side. Kind of a really ideal thing.

And one -- we tried to get both builders to work with us and do the energy efficiency and the PV, but only one agreed to. So we had this side-by-side comparison. And the project was designed before they put the PV on, so the PV got put on the easiest way to do it. And it was southeast or west.

It ended up with about 25 percent of them facing east. Still, when we, in July when we had our new peak, it helped us immensely. And we looked at the -- I mean you can do this with a computer simulation, but when you get real data showing you this, it really comes home strong.h

There's an incentive for utilities, if you're going to pay a rebate and incent people to put PV on, have it south or southwest, or even west. And if it's west, if you incent them enough, they'll lose a little bit annually but it'll help you immensely on the peak thing.

Now, I want to take my SMUD hat on, and just put my hat on as citizen of Sacramento, and -- or citizen of the country. My undergraduate degree is from the U.S. Military Academy. And as such, I, you know, years ago I stood up and swore to defend the Constitution of the United States.

And the national security is another thing that we should be entering into the formula of cost effectiveness, it's real.

I mean the tankers go back and forth, the oil companies don't pay for that, we do. It's real.

The other thing I'll just mention, and then I'll be quiet about this, is that Randy Udall and Steve Andrews formed the U.S. Chapter of the Association for the Study of Peak Oil about four years ago. And they've had -- I attended the conference that they did in Denver four years ago.

They had a conference in Boston, they had a conference in Houston, and in September, the 21st through the 28th, it's happening here in Sacramento. And they will not only address peak oil, but they'll talk about natural gas. And the concerns that you've expressed about the volatility in that area, I think, are well founded.

I would recommend that you go to Randy Udall's website; do just a search on his name and you'll see CORE, CORE. And look at his paper called methane madness. And I have a few of these, and I'll take an email card and email one if anybody else wants one that I don't have enough.

Thank you.

MS. DOUGHMAN: Thank you. Okay, --

MR. BACCEI: Oh, I just -- I mentioned the City of Sacramento and UC Davis are co-sponsoring this conference here in Sacramento.

MS. DOUGHMAN: Okay. The next blue card is from Jane Turnbull with the League of Women Voters.

MS. TURNBULL: Good afternoon; it is still afternoon. Thank you for a very interesting panel. I think we all have learned a good deal today.

There are a few questions that I still have that perhaps the panel could fill me in on. This morning Mr. Price mentioned combined heat and power and the potential that that has. I think this is something that the League's really quite enthusiastic about, but we hear it raised as something with a great deal of potential. And then nobody talks about what the potential actually is.

Is this exclusively distributed generation? I don't think that's the case.

Somewhere along the line it has to fit into this whole equation. And we'd like to see some legitimate realistic projections in terms of what is included in combined heat and power.

Secondly, what is distributed generation? Is that strictly PV on the roof, or is it small-scale combined heat and power, or are there other forms of distributed generation out there. And how does distributed generation fit into this overall portfolio of generation and resource procurement.

I think Dr. Jaske's final comments were very important regarding the issues of renewables procurement planning and how it is today, or how it still is not today.

The fact that we do have a local resource adequacy element out there, I think, is commendable. To what extent we're actually using it, and to what extent the local communities are involved in it, I think is a very big question.

Our Attorney General has asked our counties and local communities to develop energy elements in their general plans. Most communities have no idea where to start. But somewhere along the line they do have a role in this whole renewables procurement planning process.

And so I think that somewhere along the line this local resource adequacy element needs to be tied to the local communities.

I also would like very much for someone to come up with an answer in terms of whether a local community can adequately meet its long-term renewable and nonrenewable procurement requirements without transmission. Simply using distributed generation. That may be a fiction, but right now that fiction has a great deal of popularity out there. And unless we get some good answers I think that popularity will continue,.

Thank you.

MS. DOUGHMAN: Thank you.

DR. JASKE: Let me observe, Ms. Turnbull, that in the vast panoply of RPS requirements of the various states around the country, there's enormous variation in what technologies are considered part of those eligible for satisfying the requirement.

Some of them include energy efficiency, you know, as part of, in effect, a preferred resource standard, not necessarily just a renewable one. Some of them would allow for the sort of things that Mr. Baccei talked about, you know, sort of passionately, the rooftop solar or even passive design things.

So there's a whole other thought process out there in other parts of the country about how to go about pursuing, you know, a preferred resource strategy than this particular formula that, you know, we have inherited from a number of years ago here in California.

Whether that should be changed, even if the politics could allow for it to be changed, you know, or is it a third rail to even talk about changing it, you know, I don't know. I'd just observe that we have our own parochial perspective about how we define this question.

There's lots of other ways of asking the question out there in the country.

MR. HAWKINS: Yeah, I'd also like to make a response and thank you for your comments. When you think about Hawaii, Hawaii has basically isolated systems. And they basically, each island is self sufficient. And so when you look at some the interesting issues that they have, where they have really promoted wind generation. And they really have substantial interesting problems, let's put it this way, of trying to control their frequency, and some of their voltage problems.

And a number of islands, Iceland has also gone down this route, and also has some fairly interesting issues and so forth. And so those are sort of the extreme.

The advantage we have at least in the western part of the United States, and certainly in California, is the fact that we're part of this large interconnected grid. And it gives us a wonderful advantage of being able to stabilize the grid, and provide a lot of backup resources, and to move economy energy from the Pacific Northwest and others around.

So there is some advantage of having that. I certainly understand the desire for self sufficiency and what communities would like to do. And those are very interesting tradeoffs. And my, well, let's see, I guess my recommendation is that we need both.

You know, the more that we can provide local generation, the better that local community then is aware of the resource tradeoffs that they're potentially doing. And I think those are reasonably good investments to be done.

At the same time, making sure the grid is there as the backup and the thing that provides the reliability, which then provides them the economic environment for businesses and everything else to flourish, I think also has its place.

So, it's a good partnership if the two can work together.

MS. DOUGHMAN: Go ahead.

MR. PRICE: I was just going to point out that I think that the last really thorough potential study of CHP for California was done as part of the 2005 IEPR analysis. And that's the study that we looked to when we went back on CHP potential for the GHG analysis for the CPUC. So, if you can find that you probably have it.

But, for what it's worth.

MS. DOUGHMAN: Okay, any more comments from the panel? Okay, the next blue card I have is Merwin Brown, Director of Transmission, Research and Development with CIEE.

MR. BROWN: Thank you. If I may, Pam, you just asked the question, it's a fairly simple one. Name is Merwin Brown with California Institute for Energy and Environment, University of California.

This meeting today was mostly about reviewing past studies that have been done, what the messages were from them. What's the next study that needs to be done. This is directed to either each panel member or anyone who wants to volunteer. But where would you like to see the resources put? What's the next big question or questions you'd like to see answered of similar type studies?

DR. JASKE: I think from my perspective this whole constellation things associated with backing out conventional resources while adding renewables with the overlay of both -- well, with the overlay of local reliability, the sort of nut of a complicated analytic problem that hasn't had sufficient attention.

And will -- not only is it desirable to be looked at, it's essential that we look at. And part of the essentiality of it is the State Water Board and their OTC mitigation policy. It isn't yet final, but which is moving along. And it's going to, at least in many people's minds, essentially cause all the old steamers to retire.

And some of them will try to repower, and some of them will just throw in the towel and say forget it. Because, you know, a lot of them are in southern California, and the licensing logistics, you know, the air quality issues, the offsets they'd have to find are just so formidable.

Some of them will try to repower and some will bet their future, you know, in an energy forum, through a combined cycle. And some of them are going to try to just go as peakers, you know, and essentially survive on a capacity payment.

And there's probably, you know, a bunch of money available that route, which might be enough to make a plant go.

And then there's the whole other question, independent of the desires of the generators, of what are the alternatives. So, certainly various kinds of local generation, rooftop PV, combined heat and power, distributed generation, you know, all of which would, in effect, whether it's classified as a local resource, have the effect of reducing load, or potentially reduce load, and be there in that location.

And then finally, perhaps connected to your CIEE research area, is how should the transmission system be changed to allow some or all of that to happen. Is it feasible to expand transmission in that completely urbanized environment of southern California in a way that, you know, just to pick on someone, you know, the 1500 megawatts at Ormond Beach, you know, don't need to be replaced at Ormond Beach.

We don't know the answer to those questions. And the ISO has a study which is sort of launched trying to get the three PTOs to look at this OTC issue and how they might be replaced. And I'm sure they will make some progress, but this is a very complicated constellation of both problem and solution that, you know, the more resources brought to bear on it, the better.

MS. DOUGHMAN: Snuller.

MR. PRICE: I think I'd answer the question about what's needed is in terms of the next step of modeling or what-have-you, is -- and maybe this is because I do planning for a living, but I think it's more planning.

I feel like the policy, we're getting a lot of -- in an environment where there's a lot of policy that's pushing us, the 33 percent that was in the draft scoping plan at ARB is really pushing the 33 percent for all of the utilities, not just the investor-owned utilities.

There's a number of other initiatives that affect the electricity sector in there. And I'm feeling like it's time for the planning and analysis to sort of catch up.

So I feel like the policy is sort of driving the planning, rather than the planning driving the policy.

So, to me, the solution to that is to really do a good job on our planning and lay out alternative policy options that can get towards these goals that -- ambitious goals that we've laid out.

MS. MARKS: I would second what Snu says. And, as well, I started off this conversation with what the PUC intends to study. And that's really the implementation barriers to getting renewable projects online.

So, you know, we can do an analysis of what we think is possible, but then we need to, you know, take a step back and say, okay, what is physically possible, given all these implementation barriers. It's really the next level of analysis.

The analysis won't stop at what are the barriers. We also want to take it to the next step which is what are the solutions to overcome these barriers. And those solutions don't just rest with the PUC, but they rest with the CEC and the Cal-ISO, you know, the counties, and all of the local and state and federal government entities that are responsible for some aspect of bringing renewable projects online.

MS. DOUGHMAN: Dora.

DR. NAKAFUJI: Well, I think throughout this presentation folks have mentioned continuing to do these assessments periodically. But I think now that there are a lot more countries, states that are dealing with high penetration, that maybe starting to track some of the successes that they have in mitigating and adopting strategies that have worked.

I mean that, I think, will provide the confidence that we need in order to move in a direction. If we don't do that, you know, everybody's reinventing the wheel every single time.

Reliability metrics is important, and I think bringing in the utility planners perspective, as well as the operations, together. Because if we're going to keep these in stovepipes and plan it the way that the system has been planning it, this is a new paradigm.

We don't know if our current regulatory environment is sufficient. We may be completely over-shooting our current reserve requirements as more of these renewables come online. We really don't know what that's going to be like.

The other area is, I think, interdisciplinary or inter-industry impacts. We've talked about the natural gas. We've talked about the hydro and the electrical. So the electricity is the underpinning infrastructure, the critical infrastructure. And from a national laboratory standpoint that has the security perspective, this is an area we're definitely focusing on as far as vulnerability assessments and as well as looking at local disruptions and also other disruptions.

Internationally, you know, we have the border issues. And also between -- inside the state's borders.

And then coupling climate change impacts. I think that's still an area that's still out there. Because climate community speaks a different language. And taking their 100-year assessments and bringing those threads of issues to an operating environment, and communicating that to the planners and the operators. I think that's another area that hasn't really been -- the communication hasn't been very strong.

MS. DOUGHMAN: Go ahead.

MR. HAWKINS: Well, I think Dora's really put her finger on a lot of it. The whole concept is that there's a lot of individual projects and pieces that we've looked at.

We have this vision, the vision is 33 percent. That's great. So, now trying to put that together into a total picture or mosaic of how we get there, and how each of the individual little projects and studies and so forth actually fit together into making that final quilt of things that really look good, to make this work. That's the challenge.

And so I think we're starting down that direction. And it involves really working with the Commissions, as well as the utilities, very heavily involved in this. It's their customer base that is affected by the reliability and the things we do.

And so I think seeing this integration of the pieces and getting our team of people together on these things, and continuing to create that vision of how the project pieces fit together into the larger picture is the critical step.

The other piece that's missing, and Merwin and I have talked about this, is we're still missing a lot of data. If I want to make my own studies, I want to do other kinds of studies, look at impacts of things, I really know very little about some of what the renewables actually will perform like.

And I guess I'm still interested, research that provides better data, better modeling. And also we're experimenting with new transmission strategies, intelligent agents, smart devices that really help control the power grid, itself. And that research is just underway, just begun this year. And we're looking to see how those things play out.

Plus taking advantage of the next level of phaser technology which then really looks at the stability of the grid. And ultimately be able to make changes to that.

So we've got a lot of different pieces that we're working on. The research and development activities are critical. And it's also critical that the utilities, particularly the transmission owners, are engaged with that. Because if we want to install the devices or test them, it goes into their substations. And so they have to write the plans and blueprints and so forth as to how to hook them up.

So, all of those plus the communications infrastructure to make this happen, are all the pieces that we need. So, it's a complicated picture, you know. We like to simplify it, we like to think it's really easy. We'll just hook up some more windmills, some stuff like that. But it's much more complicated.

And I think recognizing that and then trying to have the vision of what that looks like, keep the vision in mind. But then let's build the overall plans to get there. So, I like your planning scenario.

MS. DOUGHMAN: Anything more from the panelists? Any questions from the phone? Any more blue cards in the audience?

Go ahead.

DR. JASKE: At the risk of a clear changing comment --

(Laughter.)

DR. JASKE: I think that one of the things that's implied by Dave Hawkins' comment, and my own earlier one, is how do all these things fit together and on what timelne.

We obviously have the message of high renewables and the year 2020 is an interesting thing on a decade, you know, that is a great slogan. But, if we got 35 percent renewables by 2025, you know, with a lot more comfort and a lot more perhaps significantly lower cost, because things could be staged a little bit better, we'd all probably, you know, after the fact, think we were better off than something that cost more and sort of got 30.5 percent by 2020, because we just didn't quite make it.

And so how do we, you know, be inspired by the vision, as Dave called it, but not get so hung up on that formula that, you know, it just becomes gridlock in terms of doing all the things that we need to do.

DR. NAKAFUJI: That's a real good question about setting expectations. I mean, you know, if we didn't set that carrot out there, or that goal out there, nobody's going to be motivated to do anything.

And, you know, is 33 percent the magic number? Who knows. I mean, 20 percent in 2012 is the --

MR. HAWKINS: Do I hear 50 --

DR. NAKAFUJI: -- number, you know, we're hearing that. So, was 2010 the magic number. Who knows. But at least -- I think the message, though, is that with all the gloom and doom out there about oil dependency and security and fossil energy, you know, meeting its peak.

It's clear that we've got to look for some alternatives. And it's not that fossil is going to completely disappear, but we've got to do something to augment that. And to the degree that we can augment it, I think that spawns the juices of innovation and the creativity that brings together, you know, the communities to try to find something alternative and new and to enhance our environment.

So, I'm not too stuck on a number, but at the same time, hey, it's a shot in the dark.

MR. HAWKINS: Well, Al Gore says we need

to get there in ten years, right, something like that.

MS. DOUGHMAN: Okay, I have a few wrap-it-up slides, so let me jump to the other end here.

Okay, I think we have discussed some of these remaining questions. But in your written comments, remaining members of the participants of the workshop and all those on the phone, if you could also address these last questions regarding existing studies.

Are there others that we've missed. And what other studies are planned or underway that we need to know about. And what additional studies are needed to better understand the impacts of higher levels of renewables on the system. Or to identify ways to mitigate those impacts.

And here I have instructions on how to provide written comments. Please provide your comments by 5:00 p.m. on Friday, August 1st. And please include the docket number, 08-IEP-1B, as in boy. And indicate 2008 IEPR update 33 percent renewable electricity in the subject line. And then you can see the notice for further instructions.

And then I have here links to all of the studies that were included in attachment A of the notice, including a link to the intermittency analysis project, the final report. And so you can look at these for further study on this topic.

So, if there are no more questions, why don't we adjourn. And thank you very much for an excellent workshop.

(Whereupon, at 4:20 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 Staff 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 5th day of August, 2008.